Electric Resource Alternatives

This section is designed to provide a brief overview of technology alternatives for electric power generation. It encompasses mature technologies but emphasis is placed on new methods of power generation with near- and mid-term commercial viability.

All data has been gathered from public sources except where noted, and in these instances is non-sensitive PSE data. It should be noted that many data sources are the manufacturers themselves, who may provide optimistic availability, cost, and production figures.

I. Demand-side Measures (DSM)

A. Energy Efficiency

Energy efficiency is defined as a technology that demonstrates the same performance for a given task as competing technologies, but requires less energy to accomplish the task.

Discretionary Measures

PSE refers to all energy efficiency improvements and upgrades to existing construction as “discretionary measures.” This may include bringing building components up to or beyond code levels, or the early replacement of existing technologies such as lighting or appliances. Similar measures exist for new construction, and are discussed below under Lost Opportunities.

Lost Opportunity

Lost opportunities refer to the moment when a customer is making a decision about acquiring new equipment. Once the purchasing decision is made, there will not be another opportunity to influence the decision towards an energy efficient technology. When new buildings are being built, the construction phase is the best time to install the most efficient measures. Also, when a customer needs to purchase new equipment, savings can be gained by purchasing high-efficiency models.

Codes and Standards

Any codes and standards with energy efficiency provisions that have been passed at the time of the 2009 IRP and slated to go into effect in the future are incorporated as non-programmatic energy efficiency savings. These are savings that impact the load growth at no cost to the company.

Lighting

Switching from highly inefficient incandescent lighting to fluorescent lighting can result in significant savings. Lighting measures for typical household applications are categorized by use: low (1 hour per day), medium (2.5 hours per day), and high (4 hours per day) represent frequency of use.

Heating, Ventilation, and Air-Conditioning (HVAC)

Measures associated with the HVAC system improve the overall heating and cooling loads on a building. They include measures such as a high efficiency DX cooling package and programmable thermostats.

Building Envelope

“Building envelope” measures improve the thermal performance of a building’s walls, floor, ceiling or windows. The baseline technology and the energy efficiency upgrades are discussed below. Building envelope energy efficiency measures include insulation (ceiling/roof, wall, and floor) and windows.

Domestic Hot Water

In addition to a more efficient water heating system, any equipment measures that require less hot water are also included in the domestic hot water measures below.

Plug Load

ENERGY STAR® rated plug-in loads reduce the overall electric load of a household compared to standard equipment. This measure identifies the specific plug-in equipment. The following list includes both typical household entertainment equipment and home-office equipment. Office equipment such as computers, monitors, and printers can all be ENERGY STAR® classified, indicating lower energy use than conventional equipment. Savings is achieved, in part, because the machine is equipped with a standby mode.

B. Fuel Conversion

When customers switch from electricity to natural gas, particularly in the case of space and water heating, electrical savings are gained from the reduction in electrical energy use.

Fuel conversion measures, specifically water heaters, space heaters, zone heaters, ranges and dryers, fall under the Lost-Opportunity Equipment category, as described above.

C. Distributed Generation

Distributed generation refers to small-scale electricity generators located close to the source of the customer's load.

Non-renewable Distributed Generation

Combined Heat and Power. Combined heat and power (CHP) plants are a more energy-efficient use of non-renewable generation units. A CHP starts with a standard non-renewable generator, but improves the overall utility by capturing the waste heat produced by the generator. For example, a typical spark-ignition engine has an electrical efficiency of only about 35%. The "lost" energy is primarily waste heat. A CHP unit captures much of this waste heat and uses it for space heating or domestic hot water. Thus, there are cost savings for the water heating in addition to electricity generation. Three-engine generator technologies are considered for use with CHP: reciprocating engines, micro-turbines and fuel cells.

Renewable Distributed Generation

Renewable generation encompasses all generation that uses a renewable energy source for the fuel; in other words, a fossil fuel is not consumed. There are two main categories of renewable generation: biomass and clean energy.

Biomass. Sometimes referred to as "resource recovery," biomass is used as the fuel to drive a generator. The source of the biomass can vary, but can be broadly categorized into "industrial biomass" or "anaerobic digesters."

Clean Energy. Generation that is achieved without the consumption of a hydrocarbon fuel. The two main sources for clean energy are wind and solar photovoltaics (PV).

D. Demand Response

Demand-response (or demand-responsive) resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. Development of Smart Grid in the future will enable the automation of demand response resources, thereby enhancing the value, benefits and flexibility of such resources. Acquisition of demand-response resources may be based on either reliability considerations or economic/market objectives. Objectives of demand response may be met through a broad range of price-based (e.g., time-varying rates and interruptible tariffs) or incentive-based (e.g., direct load control, demand buy-back, and dispatchable stand-by generation) strategies. In this assessment, we considered five demand-response options: Direct Load Control, Critical Peak Pricing, Curtailable Rates, Demand Buyback, and Distributed Standby Generation.

PSE issued two demand response Request for Proposals (RFP) in 2007 and 2008. The first was a commercial sector demand response pilot issued in August 2007. We received two proposals and awarded one contract. PSE issued a second demand response RFP for the residential sector in November 2008. We received nine proposals, and four have been shortlisted.

E. Distribution Efficiency

Distribution efficiency resources are comprised of phase balancing and conservation voltage reduction. Phase balancing eliminates total current flow losses, also known as I^2R losses, in the three phases of an unbalanced distribution system. Therefore, a concerted effort to balance phases can reduce energy loss. Conservation voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption. At reduced voltages, many appliances and motors can perform properly while consuming less energy.

II. Solar Energy

Solar energy is the harnessing of the sun's energy to create electricity or heat. Solar energy is generated in two major ways: using photovoltaics to directly convert sunlight to electricity, and using solar thermal technologies to convert the sun's energy to heat. Solar technologies have been around for decades, but these technologies have grown rapidly over the past several years as demand for renewable energy sources increases, and improved technologies and manufacturing volumes have reduced costs. At this time, solar technologies can be cost competitive in some markets where subsidies are available.

PSE's Wild Horse solar project is a demonstration of the potential for solar power output in Washington state. Located at the Wild Horse Solar Facility in Kittitas County, it was completed in 2008 and produces an output of up to 500 kW at peak performance (full sun), which is enough to serve approximately 300 households. This facility uses fixed-angle, multicrystalline photovoltaic solar-panel technology, and has the ability to produce power under cloudy skies (roughly 50% to 70% with bright overcast, and 5% to 10% with dark overcast). This project is currently the largest solar facility in the Pacific Northwest.

All solar energy used for electric generation qualifies as renewable energy under Washington's renewable portfolio standard.

A. Photovoltaics

Description of Technology

Photovoltaic (PV) cells are semiconductors which convert sunlight into electricity and represent the overwhelming majority of solar installations to date. PV currently comes in two major types, crystalline silicon and thin-films.

Crystalline silicon solar cells are manufactured from ingots of silicon grown in specialized silicon plants, similar to computer chips. These ingots are sliced into wafers and contacts are added to create solar cells. Multiple solar cells are typically joined together and encapsulated in panels.

Thin-film PV panels are made of films of semiconductor material deposited onto a substrate. The common types of thin-film PV are non-crystalline amorphous silicon (a-Si), cadmium telluride (CdTe), and copper indium gallium diselenide (CIGS). Common substrates include glass and plastic. Because of the flexibility of some substrates, large panels are easier to make, and these thin-films can be incorporated into other products, such as building materials.

Organic photovoltaics are an emerging technology, manufactured from inexpensive organic materials. They are yet to be commercialized in large volumes, but are being developed both by private industry and in universities and government labs.

The different types of solar photovoltaics have different advantages. Crystalline silicon solar cells have the highest efficiencies, typically 15% to 20%. Thin-films have a lower efficiency than crystalline silicon cells, ranging from about 7% to 13%. However, with the lower efficiency comes a lower cost. Thin-film costs are approximately 50 cents to 70 cents per watt less than multi-crystalline[1]. Due to the lower efficiency, a greater area of thin film panels is required to create the same power output as crystalline silicon panels. Competing with thin films, a relative undersupply of silicon has kept silicon PV prices high recently, but a new wave of PV-specific silicon plants is expected to cause a price drop in the coming years.

Solar panels do have some degradation of their output over time, but all come with manufacturer warranties guaranteeing their power curve for 20 to 25 years. PV panels generate DC power and require an inverter to switch to AC power. Typically, the losses for wiring and inversion in a PV system give the system an overall 80% efficiency from DC output of the panel to AC power.

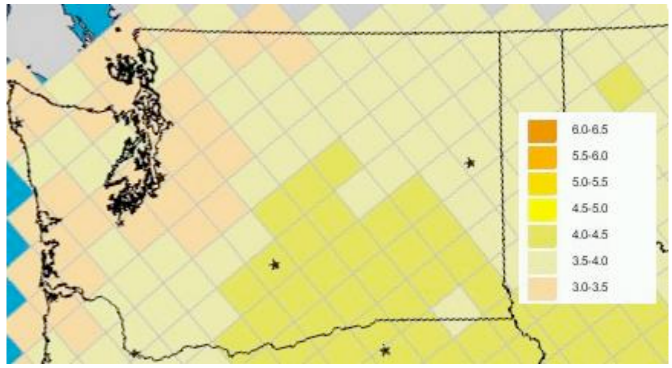
Opportunities in Puget Sound Region

In the Seattle area, average sunlight is around 3.7 kWh per m^2 per day (11% CF), contrasting with the eastern half of Washington, where sunlight is significantly better at around 4.8 kWh per m2 per day (15% CF).[2]

[1] Solarbuzz, retrieved 1/26/09.
[2] PV Watts, flat plate fixed at latitude for Seattle and Yakima and Frank Vignola, Univ. of Oregon

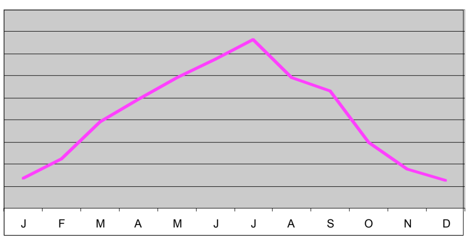
Figure F-1
Sunlight Averages for Washington State

Currently, solar projects are not eligible for Production Tax Credits, but are eligible for a 30% Investment Tax Credit. Recent changes extended this tax credit until 12/31/2016 and made it eligible to utilities and businesses. Washington state recently passed legislation that provides a solar production incentive ranging from $150 to $540 per MWh but that is capped at $2,000 per project. Solar projects receive five-year MACRS and are exempt from Washington sales tax.

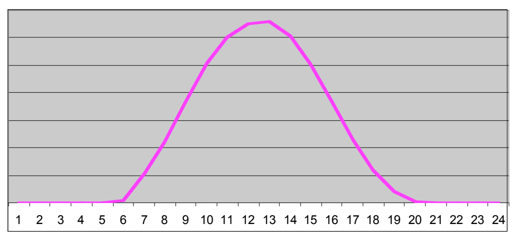


Source: National Renewable Energy Laboratories (NREL)

Figure F-2
Washington State Solar Irradiance



Annual Energy Shape (% by month)



Daily Energy Shape (% by Hour)

Notable Companies

Crystalline silicon cell and panel manufacturers	Q-Cells, Sharp, Kyocera, Suntech, BP, QCell
Thin-film manufacturers	Uni-Solar, First Solar
Developers	SunPower, SunEdison

Figure F-3
Solar Photovoltaic Key Metrics

Capital Cost w/o subsidies ($/kW)	Levelized Cost w/o subsidy ($/MWh)	Typical Installation Size (kW)	Expected Life (years)
$3,500 – $10,000	$300 - 800	3 – 15,000	20 – 25+

Source: Public Press for Large Scale Installations, Contractor estimates, PSE experience

B. Thermal and Concentration Technologies

Technology Descriptions

Thermal and concentration technologies use mirrors or lenses to concentrate direct sunlight onto a receiver. Solar thermal technologies capture the heat of the sunlight, which is then used to create steam and drive a traditional steam turbine. Concentrating photovoltaics use a high-efficiency PV cell to directly convert the concentrated sunlight to electricity. All thermal and concentrating technologies share a common characteristic of only being able to utilize direct sunlight, unlike photovoltaics, which can use both direct and diffuse sunlight. This reduces the solar energy they can harness in Washington state by about 30%. All such systems track the sun on at least one axis. Generally, solar thermal technologies are best suited for commercial or utility scale installations, as they require large installations and complicated mechanical equipment. Concentrating PV is being developed at residential scale through utility scale.

To date, solar thermal trough technologies are the most developed, with over 300 MW in service since the 1990s. The other thermal and concentrating technologies have been limited to testing or pilot installations to date, some dating back decades. Many of these technologies have commercial installations proposed.

Figure F-4
Solar Thermal and Concentration Technologies

Solar Thermal Troughs

Parabolic mirrored troughs concentrate energy onto a receiver pipe to heat a carrier fluid to temperatures up to 500 degrees C. This heated carrier fluid is then used to create steam, which is run through a steam turbine to generate power. Approximately 300 MW of solar thermal troughs are installed in California in the SEGS I – IX facilities. These were built in the 1980s and are still in operation today. There was a lull in construction of the last SEGS facility until the last two years, when several small facilities and the 64 MW Nevada Solar One facility were brought online. Additional plants have been proposed in Nevada, Arizona, and California, including the 280 MW Solana plant in Arizona, and the 553 MW Mojave Solar Park Project in California. In addition, new troughs were recently added to the SEGS systems.

Internationally, the 50 MW Andasol 1 plant started commercial operation in later 2008, and two more Andasol plants in Spain are under construction.

Solar Thermal Trough systems have the promise of including energy storage as heat. The Andasol facility in Spain is including approximately seven hours of storage, and the Solana Plant planned for Arizona will incorporate thermal storage.

Compact Linear Fresnel Reflectors

Compact Linear Fresnel Reflectors (CLFR) function similarly to solar trough systems, but instead of using large parabolic curved mirrors, these systems use motors to adjust several flatter mirrors to focus sunlight onto the receiver pipes. Some of the current systems directly generate steam in the receiver pipes, instead of using an intermediary carrier fluid. A 5 MW facility was recently commissioned in California, and a 177 MW facility is planned there.

Hybrid Solar and Thermal Plants

Several hybrids incorporating a traditional thermal generating plant with solar collectors to provide additional heat have been proposed. These include combinations with gas turbines and with biomass. The Liddell Station Coal Plant in Australia incorporates a solar thermal system to increase output. The 75 MW Martin Next Generation Solar Energy Center in Florida is under construction.

Power Towers

Power towers use a field of mirrors to focus the sun's direct rays on a central receiver. The focused sun heats a carrier fluid, which is then used to heat water into steam that drives a steam turbine to generate power.

Solar One was the first installation. It was built by the Department of Energy in 1981 and operated from 1982 to 1986. This facility was renamed Solar Two in 1995, when it was rebuilt to include additional mirrors and thermal storage in molten salt. The facility was decommissioned in 1999.

Power towers have the ability to focus more sun on the heat collecting fluid than trough systems, increasing the temperature and thus raising the efficiency of the system. They also have a smaller circulating loop for the heated fluid, minimizing required piping and heat losses. Historically, some of the problems with power towers have been maintaining the fine focus of the mirrors on the receiver, keeping mirrors clean, and the high-temperature materials used for the receiver and associated equipment.

Recently, power towers have seen renewed interest, with over 600 MW proposed in California.

Dish Engine Systems Dish engine systems are comprised of a dish of mirrors that concentrate sunlight onto a heat-driven Stirling engine. This engine technology has been proven in space programs for many years, but is yet to be rolled out in large scale manufacturing. Several manufacturers are testing their facilities in the United States, notably at Sandia National Labs and in Washington state. Several California utilities signed large PPA agreements in 2005, but it is unclear if the facilities will ultimately be built.	
Concentrating Photovoltaics Concentrating photovoltaics use a plastic lens or mirror to focus solar energy on a small high-efficiency PV cell, thus reducing the number of PV cells needed. The added heat has reduced the efficiency of the cells in some applications. The system pictured here is a 25 kW Amonix concentrating system built in 2006 in Nevada. A significant number of startup companies are focusing on commercializing concentrating photovoltaics for applications ranging from utility scale installations to individual rooftops.	

Notable Companies

Solar Thermal Trough	Acciona, Solel, Abengoa
Compact Linear Fresnel Reflectors	Ausra, Skyfuel
Power Tower	eSolar, Brightsource
Dish-Engine	Sterling Energy Systems, Infinia
Concentrating PV	Amonix, SolFocus, Sol3G, Greenvolts

Note, the limited number of installations in the market limit the accuracy of cost estimates.

Figure F-5
Solar Trough Key Metrics

Technology	Capital Cost ($/kW)	Levelized Cost ($/MWh)	Typical Installation Size (kW)	Expected Life (years)
Solar Thermal Trough[3]	$4,950	$220	25-50,000	20
Compact Linear Fresnel Reflectors	Unavailable	Unavailable	Unavailable	Unavailable
Power Tower	Unavailable	Unavailable	Unavailable	Unavailable
Dish-Engine	Unavailable	Unavailable	Unavailable	Unavailable
Concentrating PV	Unavailable	Unavailable	Unavailable	Unavailable

Source: 3

[3] Based on Nevada Solar One and Solar Tres announced capital costs

III. Biomass

The term biomass generally applies to a fuel source (or feedstock) rather than a specific generation technology. Biomass fuels are organic materials that can vary dramatically in form. Biomass fuels, biomass fuel sources, and the generation technologies used for biomass are widely diverse. Biomass fuels include but are not limited to wood residues, spent pulping liquor, agricultural field residues, municipal solid waste, animal manure, and landfill and wastewater treatment plant gas. Biomass fuel resources and power generation technologies are listed in Figures F-6 and F-7, respectively.

Of the biomass fuel resources listed in Figure F-6, all would qualify as renewable energy under Washington's renewable portfolio standard, with the exception of municipal solid waste, pulping chemical recovery (pulping liquor), and crops grown on land cleared from old growth or first growth forests after December 7, 2006. Modifications are being considered in Washington's legislature that may alter some of these provisions, but have not yet been finalized. All of the power generation technologies listed in Figure F-7 are eligible as renewable energy under Washington's renewable portfolio standard.

Figure F-6
Biomass Fuel Resources

General Classification Biomass Type	Brief Description
Forest Products:	
- Forest Residue - Mill Residue - Pulping Chemical Recovery	- Logging slash and forest thinning - Wood chips, shavings, sander dust and other large bulk wood waste - Spent pulping liquor used in chemical pulping of wood
Agricultural Resources:	
- Crop Residues - Energy Crops - Animal Waste	- Residues obtained after each harvesting cycle of commodity crops - Crops grown specifically for use as feedstocks in energy generation processes, includes hybrid poplar, hybrid willow, and switchgrass - Combustible gas obtained by anaerobic decomposition of animal manure

Urban Resources:	
- Municipal Solid Waste - Landfill Gas / Wastewater Treatment	- Organic component of municipal solid waste - Combustible gas obtained by anaerobic decomposition of organic matter in landfills and wastewater treatment plants

Figure F-7
***Biomass Conversion Technology Types*[4]**

Technology	Conversion Process Type	Major Biomass Feedstock	Energy or Fuel Produced
Direct Combustion	Thermochemical	wood agricultural waste municipal solid waste residential fuels	heat steam electricity
Gasification	Thermochemical	wood agricultural waste municipal solid waste	low or medium-Btu producer gas
Pyrolysis	Thermochemical	wood agricultural waste municipal solid waste	synthetic fuel oil (biocrude) charcoal
Anaerobic Digestion	Biochemical (anaerobic)	animal manure agricultural waste landfills wastewater	medium Btu gas (methane)
Ethanol Production	Biochemical (aerobic)	sugar or starch crops wood waste pulp sludge grass straw	ethanol
Biodiesel Production	Chemical	rapeseed soy beans waste vegetable oil animal fats	biodiesel
Methanol Production	Thermochemical	wood agricultural waste municipal solid waste	methanol

[4] http://egov.oregon.gov/ENERGY/RENEW/Biomass/BiomassHome.shtml

There is a wide array of technologies for converting biomass into power, fuel or heat. New and existing technology for using wood fuel effectively to produce power generation can be generally classified as direct combustion, co-firing, and gasification.

Direct combustion is the oldest and most proven technology. Most of today's biomass power plants are direct-fired systems, similar to most fossil fuel-fired power plants. The biomass fuel is burned in a boiler to produce high-pressure steam. This steam is then introduced into a steam turbine generator. Biomass power boilers are typically in the 20 MW to 50 MW range. While steam generation technology is very dependable and proven, its efficiency is limited. The small capacity plants tend to be lower in efficiency because of economic trade-offs and the variability and moisture contents of fuel sources limit the efficiency of the fuel. Typical plant efficiencies are in the low 20% range.

Co-firing involves substituting biomass for a portion of coal in an existing power plant furnace. It is the most economic near-term option for introducing new biomass power generation. Because much of the existing power plant equipment can be used without major modifications, co-firing is far less expensive than building a new biomass power plant. Compared to the coal it replaces, biomass reduces sulfur dioxide, nitrogen oxides, and other air emissions, though tuning and pollution controls may still be required.[5] After "tuning" the boiler for peak performance, there is little or no loss in efficiency from adding biomass. This allows the energy in biomass to be converted to electricity with the high efficiency (in the 33% to 37% range) of a modern coal-fired power plant. Most co-firing plants operate with small amounts of biomass input to limit ash generation and slagging.

Gasification is the process of heating organic materials in an oxygen-starved environment until volatile pyrolysis gases (carbon monoxide and hydrogen) are released from the wood. Depending on the final use of the typically low-energy wood gas, the gases can be mixed with air or pure oxygen for complete combustion and the heat that is produced can be transferred to a boiler for energy distribution. Otherwise, the gases can be cooled, filtered, and purified to remove tars and particulates and used as fuel for internal combustion engines, micro turbines, and gas turbines. The use of pure biomass gas in a combustion turbine is in early research. Biomass Integrated Gasification Combined Cycle (BIGCC) technologies have been experimented with, but they are not yet commercially viable. Demonstration projects include the McNeil Power Plant in Burlington, Vt.

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[5] http://www.eia.doe.gov/oiaf/analysispaper/biomass/

Pyrolysis is the process of heating solid materials in an oxygen-starved environment until volatile gases are released and the solid material starts to break down and volatilize. This creates a synthetic gas that can be condensed for refining into liquid fuels, as well as charcoal that can be further burned in another process. Depending on the temperature and length of the heating, the degree to which the material is volatilized is affected. Pyrolysis is being used somewhat for production of liquid fuels.

Anaerobic Digestion uses naturally occurring bacteria and other microorganisms to quickly degrade organic slurries, often animal manures or activated sludges in wastewater treatment plants. This degradation is done in an environment with limited oxygen, which causes the bacteria to release methane and other gases as a byproduct of decomposition. These gases typically have a heat content of about 500 to 600 btu per cubic foot, about half of the heat content of natural gas. The gases can be filtered and combusted in a boiler or internal combustion engine. These gases have been used to generate power and fuel vehicles.

Figure F-8
Biomass Power Technology Types[6]

Biomass Type	Technology	Size
Solid Fuels (agricultural, municipal solid waste, forest residue, mill residue)	Direct fired / steam turbine or Direct co-fire with coal	5, 10, 25, 50, 100 (MW) 7.5, 15, 30 (MW)
Biogas/Manure	IC-engine	65, 130, 650, 750 (kW)
Biogas/Landfill	IC-engine	1, 5 (MW)

As shown in Figure F-8 above, biomass generation can range from very small scale to utility scale power production. The diverse biomass fuel types and technology choices make biomass a complex resource to analyze for an electrical generation resource. There are many factors and determinates to consider before choosing biomass generation. Providing cost estimates for wood energy systems requires flexibility and a technical understanding that costs fluctuate widely depending on the site requirements and present site capabilities.

[6] http://www.westgov.org/wga/initiatives/cdeac/Biomass-full.pdf, PSE Experience

Like most combustion technologies, biomass generation's high energy cost is largely driven by the cost of the fuel itself. The technology also has a high capital cost, and is only half as efficient as a combined cycle gas turbine of similar size.

Biomass is a widely distributed resource. Fuel competition and transportation costs typically preclude the construction of power plants with capacities greater than 50 MW. Many existing biomass plants in the Northwest function as cogeneration facilities sited adjacent to a forest products plant. Most pulp and paper mills, and some sawmills, use waste biomass from their processes to fire boilers. The high-grade steam from these boilers is used to generate power, and then the lower-grade steam is reused for process heat. Most future power plants fueled by dry biomass resources are likely to be in the range of 15 MW to 30 MW. The local market for available supply of wood may limit the benefits of burning wood fuel. Hauling wood biomass from outside a 50-mile radius is usually not economical.

Many existing biomass plants source their biomass from waste forest products, and the availability and pricing of hog fuel used for many existing biomass facilities fluctuates with the productivity of the forest products industry. A rigorous life-cycle analysis is necessary to fully understand the fuel supply chain and options to diversify fuel supply. Initial costs of wood biomass generation facilities are typically 50% greater than those of a fossil fuel generation system due to the fuel handling and storage system requirements, and ongoing labor costs are higher as there are additional fuel handling systems to be maintained.

Biomass power is reliable base load electric power, but cannot easily perform load-following. Further, because many biomass facilities in the northwest are configured as cogeneration facilities, these may not be routinely dispatched due to process needs of the steam host and the inherent limitations of a combustion/steam-cycle power plant.

Obvious benefits may be gained by burning wood residues to reduce a manufacturer's fuel oil and electricity bill. These benefits may be offset by high capital costs, low plant efficiency, and increased maintenance levels. Of course, the economics of wood waste energy generation becomes more attractive as traditional fuel prices increase and as reliable biomass sources are available at competitive prices.

There are 45 potential sources of biomass in Washington state, according to a December 2005[7], report, "Biomass Inventory and Bioenergy Assessment: An Evaluation of Organic Material Resources for Bioenergy Production in Washington State." Categories included field residues, animal manures, forestry residues, food packing/processing waste, and municipal wastes. The report states that Washington has an annual production of over 16.9 million tons of underutilized dry equivalent biomass, which is capable of producing, via assumed combustion and anaerobic digestion, approximately 1,769 MW of electrical power. Looking to just forestry resources (mostly mill residues and pulping recovery), the totals are approximately 945 MW. This study does not consider economic or commercial issues. Therefore, these results seem to be extremely aggressive and the report is based on the absolute potential, not viable or economic potential.

Several new biomass power projects have been developed or proposed in the Northwest recently. Sierra Pacific Resources installed a 23 MW cogeneration facility in Burlington, and plants are planned for Lakeview, Ore., and Warm Springs, Ore.

In addition to traditional biomass power projects, many anaerobic digesters are being built in the Northwest. These typically have capacities ranging from 500 kW to 2 MW. In Washington state, digesters are operating in Lynden, Sunnyside, and Monroe, and an additional digester is under construction in Mount Vernon.

During PSE's 2004 and 2006 RFP cycles, we received and evaluated three proposals for biomass cogeneration totaling 100 MW. We received no proposals for biomass facilities during the 2008 RFP cycle. Considering the impact of the Washington state Renewable Portfolio Standards (RPS), and the potential demand for diverse renewable resources, biomass may look more economically attractive as the demand grows, though it is expected to continue to be tied to the forest products industry in the near term.

[7] http://www.pacificbiomass.org/documents/WA_BioenergyInventoryAndAssessment_200512.pdf

Additional References:

- http://www.fpl.fs.fed.us/tmu/wood_for_energy/wood_for_energy.html
- http://www.nwcouncil.org/energy/powerplan/5/Default.htm
- http://www1.eere.energy.gov/biomass/
- http://www.nrel.gov/biomass/
- http://www.eia.doe.gov/oiaf/analysispaper/biomass/
- http://www.calbiomass.org/
- http://www.energytrust.org/bio/
- http://www.pacificbiomass.org/

IV. Fuel Cells

Fuel cells have been touted for their potential as an alternative to the internal combustion engine, but are examined here predominantly for their application in stationary power generation. The United States is a dominant fuel cell developer. The market for large fuel cell generation (>10 kW) is dominated by four types of cells: phosphoric acid, solid oxide, proton membrane exchange, and molten carbonate. Prices remain uncompetitive at around $4,500 per kW, although a new unit marketed at $2,500 per kW is expected to come on the market in 2009, and the Department of Energy (DOE) has set a target of $400 per kW by 2010.[8] [9]

Most fuel cells today operate using natural gas or hydrogen. Because of the fuel source, these would not be considered renewable energy sources under Washington's renewable portfolio standard. However, if a renewable fuel source such as anaerobic digester gas from a wastewater treatment plant was used as a fuel, the energy would count as renewable in Washington state.

A. Phosphoric Acid Fuel Cells (PAFC)

PAFC technology was the first to market and remains the most common. PAFC cells are limited to stationary applications as they are large, heavy, expensive, and slow to start. Their advantages in maturity and lifespan, however, have given PAFC the largest market share in stationary applications. PAFC fuel cells are predominantly manufactured by United Technologies and Fuji.

B. Proton Exchange Membrane Fuel Cells (PEMFC)

PEM fuel cells are generally thought to be the technology of choice for mobile applications, but have more limited roles in stationary situations. PEM fuel cells operate at much lower temperatures and have a long lifespan, but require an expensive platinum catalyst. PEM cells are very sensitive to fuel impurities and require pure hydrogen. Ballard Power Systems of Vancouver, B.C. is a world leader in PEM fuel cell development, although many auto manufacturers also conduct their own PEM research.

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[8] Fuel Cell Today, http://www.fuelcelltoday.com/media/pdf/surveys/2008-LS-Free.pdf
[9] DOE, http://www.fossil.energy.gov/programs/powersystems/fuelcells/

Ballard markets a stand-alone 1 kW unit for sale in Japan that includes a natural gas reformer and co-generates hot water and power.

A type of PEM cell, the direct methanol cell, is being tested for small portable applications, such as laptop computers. By using methanol, or another liquid fuel, energy density is increased and compression requirements decreased over PEMs fueled directly with hydrogen. Larger PEM cells have typically not used liquid fuels due to the availability of hydrogen and the added expense and maintenance associated with reforming other fuels into hydrogen for use in the PEM cell.

C. Molten Carbonate Fuel Cells (MCFC)

MC fuel cells operate at much higher temperatures, but also much higher efficiencies than phosphoric acid fuel cells. The higher temperature of molten-carbonate fuel cells functions as an internal reformer and allows it to internally reform a variety of gasses, but also lengthens start-up and shut-down. Among the world's largest MCFCs is a 1 MW demonstration plant in Renton, Wash. at the South Wastewater Treatment Plant which operated from 2004 to 2006[10]. This demonstration used both gas from anaerobic digesters at the plant, and natural gas from PSE. The Environmental Protection Agency provided approximately $12.5 million of the $22 million project cost. The largest challenge with MCFC is to lengthen the lifespan of the fuel cell stack, which has lower durabilities (8,000 hours) due to the high temperature of operation.

D. Solid Oxide Fuel Cells (SOFC)

SO fuel cells operate at higher temperatures than MCFCs, and accept an even wider variety of fuels.[11] In addition, the high temperature precludes the need for noble metal catalysts, reducing costs.[12] SOFC technology is still in early stages of development but is expected to have an increasingly important role in stationary applications. Figure D-9 shows the number of new large scale fuel cell projects by technology type and the rise of SOFC starting in 2003. Cogeneration systems are particularly attractive with solid oxide cells, due to the high operating temperature. See Figure F-9.

[10] King Country, http://www.kingcounty.gov/environment/wastewater/EnergyRecovery/FuelCellDemonstration/Library.aspx
[11] E-sources, http://www.e-sources.com/fuelcell/fuelcell-intro.htm
[12] CEA, http://www.cea.fr/var/cea/storage/static/gb/library/Clefs50/pdf/087a091giraud-gb.pdf

Figure F-9
Fuel Cell Operating Temperatures and Efficiencies

Fuel Cell Type	Development Stage	Projected Efficiency (w/heat recovery)	Operating Temp. (°C)	Lifespan (hrs)	Fuels
Phosphoric Acid	Commercial	40% (85%)	150-200	40,000 - 60,000	Hydrogen Natural Gas
Proton Exchange Membrane (PEMFC)	Demonstration	25-35% (70-90%)	50-100	40,000	Hydrogen Methanol
Molten Carbonate (MCFC)	Demonstration	45% (80%)	600-700	5,000-20,000	Hydrogen Methane Natural Gas
Solid Oxide (SOFC)	R&D	40% (90%)	600-1000	20,000	Hydrogen Methane Natural Gas

Sources: 13, 14, 15

[13] DOE, http://www.eere.energy.gov/hydrogenandfuelcells/fuelcells/pdfs/ fc_comparison_chart.pdf
[14] Siemens, http://www.powergeneration.siemens.com/products-solutions-services/products-packages/fuel-cells/
[15] Dr. Karl Kordesch, http://www.electricauto.com/fc_compare.html

V. Water Based Generation

Water based generation can be broken into four distinct categories: hydroelectricity, wave energy, tidal or in-stream energy, and ocean thermal conversion.

A. Hydroelectricity

Large scale impoundment and diversion hydroelectricity is the backbone of power generation in the Pacific Northwest. However, large-scale projects are now difficult to build because of their large capital costs, regulatory burdens and environmental concerns.

Smaller scale hydroelectricity, on the other hand, has received attention due to its somewhat smaller implementation barriers. The DOE defines "small" hydropower as generation capacity less than 30 MW, while "micro" hydropower refers to anything less than 100 kW.[16] In one example, Crown Hill Farm in Oregon successfully installed 25 kW of micro-hydro capacity. To do so, they invested $100,000 and dealt with 12 government bureaus over the course of 18 months.[17] PSE currently has 4 customers that have installed micro-hydro systems connected to PSE. In addition, we hold long-term contracts with 8 small hydro systems in our service area.

Under Washington's existing renewable portfolio standards, only efficiency upgrades to existing hydroelectric plants count as renewable energy. These efficiency upgrades must be completed after March 31, 1999 and cannot result in new impoundment of water.

B. Tidal and In-Stream Energy

For the purpose of this brief, river in-stream energy and tidal energy are viewed as equivalent, as the equipment and siting processes are expected to be similar. The roots of tidal energy are related to the development of wind energy resources. Both technologies rely upon a multi-blade rotor to supply rotational energy to a generator. As with wind turbines, a speed increaser is required due to the physical limitations of the generator size and rotor diameters.

[16] DOE, http://www1.eere.energy.gov/windandhydro/hydro_plant_types.html
[17] Oregen DOE, http://egov.oregon.gov/ENERGY/CONS/BUS/docs/CrownHill.pdf

Most tidal energy development appears to be centered on the conventional “open” turbine that is very similar to contemporary wind turbines: a “ducted” turbine where the turbine blades are enclosed within a venturi shape, or a hybrid Gorlov design with its characteristic spiral shaped turbine blades.

Figure F-10
Examples of Tidal Turbine Designs

When compared with wind turbines, tidal energy has two unique advantages: its predictable nature; and the possibility of using smaller rotor diameters for the same power output (owing to the mass flow density differences between air and water). Tidal currents are also bi-directional, which requires some of these turbine designs to pivot 180º to generate energy when the tidal current reverses its direction on the following tide cycle, while others have been designed to capture the tidal flows from both directions from a fixed position. While tidal generation is anticipated to be very predictable, it is not expected to have a significantly greater capacity credit than wind since its output over time may not correlate with high load hours.

Tidal power continues to face significant technical, environmental, and legal challenges. Generation equipment remains in testing phases, and the industry has not consolidated to a common design, as the wind industry has. Project permits in the United States are spread between federal, state, and local agencies, and a formal process has not yet been designed. Finally, subsidy and development programs vary considerably from state to state and country to country.

Tidal energy would count as renewable energy under Washington’s renewable portfolio standard.

Globally, testing of tidal generation equipment is underway at several locations; notably the Strangford Lough in Ireland, the Roosevelt Island Site in New York, the European Marine Energy Center in Scotland, the Western Passage in Maine, the Hastings Dam in Minnesota, and Vancouver Island, B.C. Several developers are calling their sites “commercial.” To date, however, none of these sites has been built out to its planned scale.

Nationally, the Federal Energy Regulatory Commission (FERC) has granted 29 preliminary permits for tidal energy projects, and another 115 preliminary permits for in-river projects as of early 2009.

In the Puget Sound region, preliminary permits for development of tidal energy are held by Snohomish County PUD for seven sites, shown in the table and maps below. Snohomish County PUD is working on feasibility studies for these sites, and is planning a test installation at one of the sites, likely Admiralty Inlet, by about 2015. Tacoma Power holds a preliminary permit for the Tacoma Narrows. After completing several feasibility studies, Tacoma Power has decided not to move forward with further activities in the narrows.

Figure F-11
FERC Preliminary Permits for Tidal Energy Locations within Puget Sound

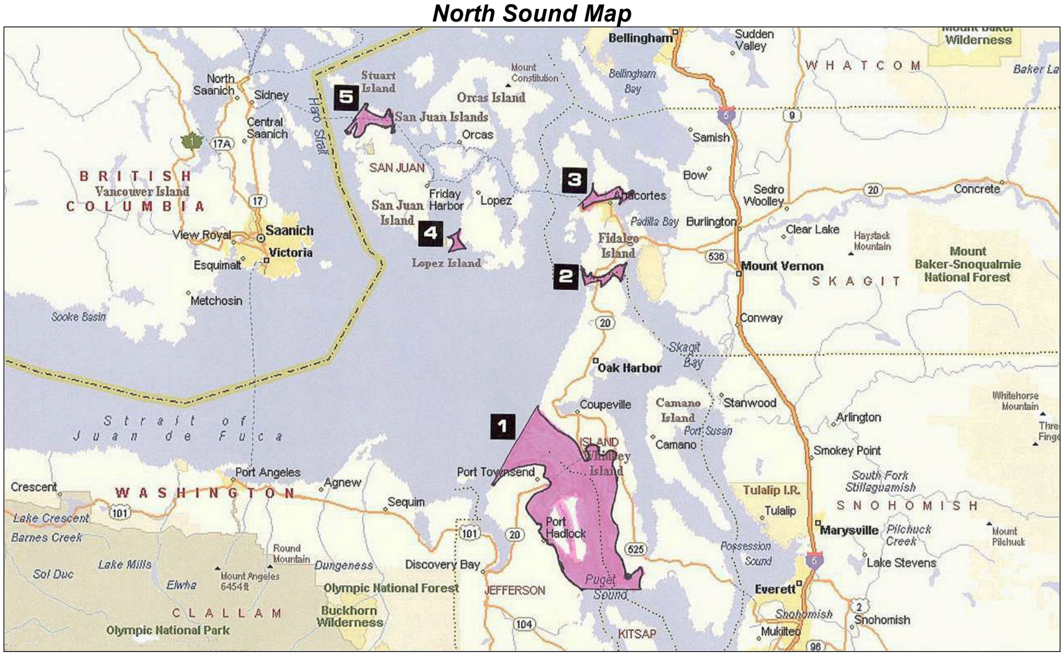
FERC ID#	Location	Developer	Estimated Annual Output[18]	Equivalent Wind Farm (30% CF)
12687	Deception Pass	Snohomish Co. PUD	20,700 MWh	7.9 MW
12688	Rich Passage	Snohomish Co. PUD	8,560 MWh	3.3 MW
12689	Spieden Channel	Snohomish Co. PUD	32,470 MWh	12.4 MW
12690	Admiralty Inlet	Snohomish Co. PUD	146,200 or 75,600 MWh[19]	55.6 MW
12691	Agate Passage	Snohomish Co. PUD	340 kW[20]	0.3 MW
12692	San Juan Channel	Snohomish Co. PUD	33,270 MWh	12.7 MW

[18] The estimated annual outputs are as reported in the preliminary permit applications submitted to FERC.
[19] The estimated annual output by Snohomish County PUD for the Admiralty Inlet location depends on the transect where the turbines are installed within Admiralty Inlet. The Point Wilson to Admiralty Head transect was estimated at 146,200 MWh and the Bush Point to Nodule Point transect was estimated at 75,600 MWh.
[20] Snohomish County PUD did not report an estimated annual output for the Agate Passage location.

FERC ID#	Location	Developer	Estimated Annual Output[18]	Equivalent Wind Farm (30% CF)
12698	Guemes Channel	Snohomish Co. PUD	28,500 MWh	10.8 MW
12612	Tacoma Narrows	Tacoma Power	120,000 MWh	45.7 MW

Figures F-12 and F-13 map of the various Puget Sound locations.

Figure F-12
Puget Sound Tidal Energy Locations with FERC Preliminary Permits
North Sound Map



Source: www.pstidalenergy.org, March 2007

Map Key:

1. Admiralty Inlet
2. Deception Pass
3. Guernes Channel
4. San Juan Channel
5. Spieden Channel

Figure F-13
Puget Sound Tidal Energy Locations with FERC Preliminary Permits
Central Sound Map

Source: www.pstidalenergy.org, March 2007

Map Key:

6. Agate Passage
7. Rich Pass
8. Tacoma Narrows

Also in Puget Sound, but not under FERC jurisdiction, is a small, ducted tidal energy device developed by Clean Current Turbines and deployed at an ecological preserve located at the southeastern corner of Vancouver Island in British Columbia. The majority of the funding for this project was provided by EnCana™, a natural gas and oil provider with locations in both Canada and the United States. This project is ongoing, with additional work planned in 2009.

Pearson College provided the host site for the project, and both the government and parks departments of British Columbia provided the necessary permits. The project was originally installed in 2006, and a new turbine was just installed in late 2008. The output of the project is used to power a lighthouse and research facilities on the island.

The Electric Power Research Institute's (EPRI) estimated summary of the economics for a full installation at the Tacoma Narrows is provided in Figure F-14. It is important to note that no commercial installations exist and these estimates are highly theoretical.

Figure F-14
Tacoma Narrows Tidal Plant Cost Estimates

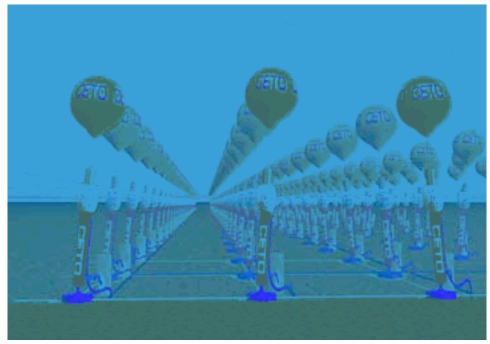
Project	Capital Cost ($/kW)	Levelized Cost ($/MWh)	Commercial Installation Size (kW)	Expected Life (years)	Typical Capacity Factor
Tacoma Narrow Tidal Plant Cost Estimates	$2,300 / kW	$112	16,000	20	35 %

Source: Electric Power Research Institute, EPRI

C. Wave Energy

Wave energy devices are early in development, but have potential for considerable power in the future, as many locations globally have significant wave energies. The major technology types, shown in Figure F-15, are floating point collectors, such as the AquaBuOY and the OSU Permanent Linear Generator, the submerged point collector, such as the CETO, floating linear collectors such the Pelamis Wave Energy Converter, and Oscillating Water Column Generators, such as the Limpet and Oceanlinx.

Figure F-15
Examples of Wave Energy Conversion Devices

Floating Point Collector	**Submerged Point Collectors**
The AquaBuOY by FINAVERA Renewables 	CETO by Renewable Energy Holdings 
Floating Linear Attenuator	**Oscillating Water Column**
The Pelamis Wave Energy Converter by Ocean Power Delivery LTD 	The Land Installed Marine Power Energy Transmitter (LIMPET) by Wavegen® 

Floating point collectors use the difference in motion between rising and falling waves and the tethered device to either pressurize a hydraulic system, such as the AquaBuOY, or to move a linear generator, such as the OSU Permanent Linear Magnet Generator Buoy. As an example, the AquaBuOY makes use of two hose pumps that alternately produce streams of water that drive a small Pelton wheel, which in turn drives a generator.

Submerged point collectors such as the Archimedes Wave Swing or the CETO, use a similar principle to a floating point collector using a hydraulic system. The differential motion between the fixed bottom of the collector and the top of the collector, which moves in the waves, drives a hydraulic system that turns a generator. This generator may be located underwater with the device, or on-shore.

Floating Linear Collectors, notably the Pelamis, are the most sophisticated and commercially mature wave energy equipment. These devices use the differential motion of floating buoys to pressurize a hydraulic system. Electrical energy is produced as the flow of oil through the hydraulic system rotates hydraulic motors attached to electrical generators. The key features of the Pelamis design are large cylindrical floats that attach directly to the hydraulic rams within a power module. Each power module is located between a pair of floats and the positions of the hydraulic rams within the power module allow the Pelamis device to convert both the vertical and horizontal movement of the floats into electrical energy. A 2.25 MW commercial facility using Pelamis equipment started operation off the north coast of Portugal in September 2008. Another project is planned off of the coast of Scotland, with a potential commercial operation date in 2009.

Oscilllating Water Column Devices, notably the LIMPET and a device from Oceanlinx, rely upon wave action to initiate airflow through a turbine attached to an engineered structure located at either an on-shore or off-shore location with substantial wave activity. This structure consists of a series of inclined, open chambers with one end submerged in the sea. The wave action results in oscillating water columns inside the structure, which expel air as the wave impinges upon the structure and create a vacuum as the water columns drop during the subsequent trough before the next wave arrives. This, in turn, necessitates a bi-directional air driven power turbine to capture the energy of the air as it is both expelled and drawn back into the engineered structure. The LIMPET, which has a capacity of 500 kW, has been operating along the coast of Scotland since 2000, and a larger installation is planned for an island off Scotland.[21] The Oceanlinx device has a prototype installation operating in Australia, and additional projects planned in Australia, the Cornwall Wave Hub in the UK, Namibia, Hawaii, and Mexico.

Several wave power sites have been proposed for the West Coast of the United States. Gray's Harbor Ocean Energy has applied for a permit for two combination wave and wind generating platforms near Ocean Shores, Wash. In Oregon, Ocean Power Technologies has proposed two projects, one in Reedsport, and the other in Coos County. Douglas County, Ore. is also working on developing a project with Wavegen.Several proposed developments have also recently been abandoned.

[21] http://www.wavegen.co.uk/news-npower-siadar-planningok%20jan%2009.htm

Wave energy does qualify as renewable energy under Washington's renewable portfolio standard.

Wave energy is derived from wind blowing across the sea, which creates waves. As such, wave energy is affected by weather, and is subject to some inherent unpredictability over the longer term. Wave heights and intensities can be predicted several days out, so short-term predictions are possible with reasonable accuracy.

While wave energy technology is perceived to have less potential impact on marine life than its tidal energy counterpart, it still faces similar challenges. As with tidal energy plants, commercial scale wave energy plants will have multiple units, with sophisticated anchoring and power transmission systems. This means each plant will have its own potential impact to the local aquatic environment. Underwater construction challenges, permitting processes with both local and federal agencies, and access to grid interconnection points must also be resolved at each potential wave energy location before the wave energy plant can proceed to commercial scale and become a viable renewable energy resource.

EPRI's estimated summary of the economics for a full commercial installation off the Oregon Coast using a Pelamis machine is provided in Figure F-16. It is important to note that no commercial installations exist, and these estimates are highly theoretical. For instance, the recent Pelamis installation in Portugal had capital costs closer to $6,000 per kW, and the UK Carbon Trust estimates that future installations will have capital costs ranging from $3,375 per kW to $6,747 per kW.

Figure F-16
Wave Energy Plant Cost Estimates

Capital Cost ($/kW)	Levelized Cost ($/MWh)	Commercial Installation Size (kW)	Expected Life (years)	Typical Capacity Factor
$3,375 – 6,747/ kW	$150-240/MWh	90,000	20	40 %

Sources: UK Carbon Trust, EPRI

VI. Waste to Energy Technologies

Waste to energy technology refers to methods of generating heat and power from energy that would otherwise be lost. This includes the collection and use of landfill gas, the incineration of solid waste, and the capture of energy lost in industrial processes. All forms of waste to energy technology are considered green, albeit to varying degrees.

Under Washington's renewable portfolio standard, landfill gas does qualify as a renewable energy resource, but municipal solid waste does not. Under revisions to Washington's renewable portfolio standard, the definitions of wastes and biomass would be clarified to allow some new wastes, such as food wastes, to qualify as renewable energy sources.

A. Landfill Gas (LFG)

The EPA requires the collection of landfill gas (LFG) at nearly all U.S. landfills. They can sell the LFG, or use it to generate electricity. There are approximately 2,400 landfills in the United States. Of these, 658 have landfill gas use projects in operation or under construction. Of these projects, approximately 72% convert the gas to electricity, with a total capacity of 1,600 MW. The actual energy produced from these projects will vary over time, as the gas production of each landfill varies. Washington state has five landfills generating electricity from landfill gas, totaling 15 MW of capacity. The largest of these is the Roosevelt Regional Landfill in Klickitat County. The EPA estimates that King County has nearly 33 million tons of unused waste in candidate landfills, enough for approximately 26 MW of generation.[22]

LFG is comprised of approximately 50% methane, and 50% CO_2, with trace amounts of other gasses. Although combustion of this gas does result in a net increase of greenhouse gasses, it is considered a renewable energy and qualifies for many renewable portfolio standards.

[22] EPA Landfill Methane Outreach Program ("LMOP") Database, http://www.epa.gov/landfill/proj/xls/mopdata.xls

B. Incineration of Municipal Solid Waste (MSW)

Only 14.7% of U.S. municipal solid waste (i.e. common trash) is directly incinerated, from which about 2,500 MW are generated nationwide. The primary reason for incineration is the reduction (up to 90% by volume) of the waste to be landfilled.[23] In nations with limited space or strong mandates, incineration is more common. For example, Singapore incinerates 90% of its municipal solid waste, and Germany banned landfilling of wastes in 2005.[24]

Figure F-17. Emissions Control Improvements

	1992 % of Waste Total	1999 % of Waste Total
Cadmium	35.9%	0.8%
Mercury	17.5%	1.3%
Arsenic	1.2%	1.0%
Chrmomium	9.3%	0.2%
Nickel	1.8%	0.3%
Lead	5.5%	0.1%
Particulates	0.3%	<.1%
Nitrogen Oxides	0.2%	0.2%
Sulphur Dioxide	0.1%	<.1%
Dioxins and Furans [a]	57.3%	4% [b]

[a] I-TEG : International Toxic Equivalent. This is derived as the sum of the Toxic Equivalent Factor (TEF) of all the dioxins and furans present in a mixture. The TEF for each compound is its relative toxicity in relation to the most toxic dioxin 2,3,7,8 - tetrachlorodibenzo-p-dioxin (TCDD)

[b] 1998 Data

Source: UK emissions in detail 1999, National Atmospheric Emissions Inventory

Historically, the public has opposed incineration, predominantly because of environmental concerns. For example, efforts to build a Seattle-area incineration facility were halted in the late 1980s. Although emissions controls have improved significantly since the 1980s (see Figure F-17), public opposition to waste incineration remains. Further, the economic benefits of waste incineration can be limited when landfill fees are low.

C. Other Waste to Energy (WTE) Processes

1. Pyrolosis

Pyrolosis is a thermochemical process that involves heating waste to between 750 and 1,600 degrees Fahrenheit in an oxygen and water-free environment, which separates the hydrocarbons. Products of the pyrolysis of municipal solid waste (MSW) are a syngas made up of hydrogen, CO, inert gases, tars and oils, and solid char materials. There

[23] EPA, http://www.epa.gov/cleanenergy/muni.htm
[24] UN Environment Program, http://www.unep.or.jp/ietc/estdir/pub/msw/sp/sp5/sp5_1.asp

were several experimental facilities for pyrolysis of MSW operated in the United States in the 1970s and 1980s, but none remain today. A facility in Germany has been in operation since 1983.

2. Gasification

Gasificiation is a thermochemical process that involves partially combusting organic materials at high temperatures (typically 1,600 to 2,200 degrees Fahrenheit) in an environment with controlled amounts of oxygen. This partial combustion creates a synthetic gas of moderate btu content composed mainly of carbon monoxide, hydrogen, and inert gases. The resulting synthetic gas can be purified and combusted in boilers or internal combustion engines. Gasification has also been used for woody biomass and coal. Gasification can accept many feedstock types, but requires a much more uniform feedstock than waste incineration.

Several experimental plants operated in the United States in the 1970s and 1980s, but all were shutdown or converted to other uses. Operating plants remain in Europe and Japan, and there has been some renewed interest in the United States to avoid landfilling, notably in California.

3. Plasma Gasification

Plasma Gasification is an adaption of a plasma-enhanced melting process developed for treatment of hazardous and radioactive wastes. Waste is heated in an insulated chamber by a plasma (electrically conducting gas) with a high voltage current. This heat volatilizes the organic components of the waste, which are then reacted with steam to make a hydrogen-rich synthesis gas. This hydrogen-rich gas can be combusted to make electricity. Metals and minerals released from the plasma process are captured for recycling. InEnTec, a company in Richland, Wash., has commercialized this process and has seven operating facilities globally, with additional facilities under construction.

4. Reverse Polymerization

Reverse Polymerization is a process by which microwaves bombard solid waste in a low-oxygen environment and generate hydro-carbons. The hydro-carbons can then either be used to generate electricity, or refined for industrial uses. This process can be applied to plastics, but is most commonly discussed in relation to tire disposal. Tires have a higher heat content than coal and generally have a negative fuel cost.[25]

The key advantage of reverse polymerization over incineration is the ability to recover the tire's carbon black and steel. This allows for 100% recycling of the tire. The results of this are similar to tire pyrolysis, although pyrolysis is not currently commercially viable. Reverse polymerization is in early development, and is also not yet commercial.

D. Waste Heat Recovery

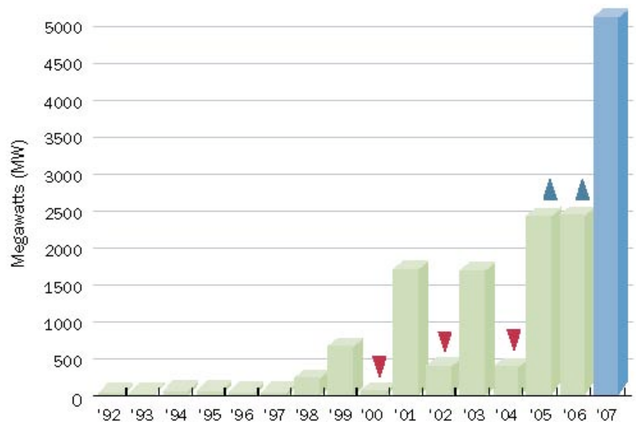
Waste heat recovery projects typically harness exhaust heat to generate power. Recovery projects tend to be small in scope (less than 10 MW), as facilities with significant volumes of waste heat generally incorporate heat recovery into the original design. Specifics such as heat rates, availability and costs are highly project specific, depending on the volume and method of heat recovery. Many of these projects focus on high compression equipment, cement plants, or industrial processes.

[25] EPA, http://www.epa.gov/epaoswer/non-hw/muncpl/tires/faq.htm

VII. Wind Energy

Wind energy is the lowest cost alternative energy technology in the United States, and capacity is growing rapidly, as shown in Figure F-18. In 2008, U.S. wind capacity increased by 8,358 MW[26], accounting for about 42% of the entire new power-producing capacity added in the United States last year. Total installed wind energy capacity in the United States now exceeds 25,000 MW[27]. The recent extension of the Production Tax Credit (PTC), and addition of alternative tax credits in the new economic stimulus bill, should continue this trend. With the completion and reliable commercial operation of our Hopkins Ridge and Wild Horse wind farms, PSE has a strong familiarity with wind energy. This section addresses onshore wind technology as well as the potential for offshore wind farms.

Figure F-18. U.S. Wind Capacity Growth



Source: AWEA, "Wind Power 2008"

A. *Onshore Wind Power Trends*

A wind turbine transforms the kinetic energy of the wind into electrical energy for transmission and use at a utility customer's home or business. Utility-scale wind turbines for land-based wind farms are available in several rotor diameters and nameplate capacities. Rotor (blade) diameters typically range from 75 meters to 100 meters, with towers of roughly the same size. A 90-meter diameter turbine with a 90-meter tower would have a total height from the tower base to the tip of the rotor of approximately 135 meters (442 feet).

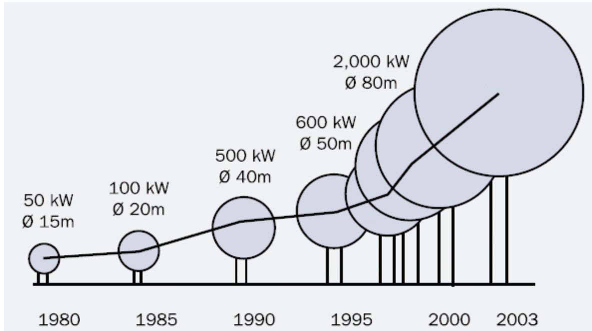
The Danish Wind Industry notes three trends in grid connected turbines:

- Growth in size, height and capacity of turbines
- Increases in efficiency
- Decreased investment costs

[26] According to 2008 data from the American Wind Energy Association ("AWEA")
[27] According to 2008 data from the Global Wind Energy Council

Although the cost of turbines has risen in the last few years (a short-term spike driven by robust demand and limitations on manufacturing and supply logistics), all three of these design trends have held true long term. The cost spike may abate due to the current recessionary economic outlook and relative illiquidity of capital, but is expected to return to a robust growth cycle as stimulus package funding begins to enter the economy.

Figure F-19
Growth in Wind Turbine Capacity



Source: European Wind Energy Association (EWEA)

Wind turbines, towers, and blades are all growing in size, driven by relatively fixed O&M costs, a desire to reduce incremental construction cost, and the presence of stronger and more stable winds at higher rotor hub heights. Better designs, materials, and manufacturing are improving efficiency and reliability.

In the state of Washington, 13 wind projects are operational with a total electrical capacity of 1,375 MW. Washington ranks fifth in the nation for installed wind capacity, while Texas ranks number one, with 7,116 MW.

Figure F-20
Washington State Wind Capacity

Name	Location	Power Capacity (MW)	Units	Turbine Mfr.	Developer	Owner	Power Purchaser	Year Online
Windy Point	Klickitat County	8	4	REPower	Cannon	Cannon	Puget Sound Energy	2008
Hopkins Ridge II	Columbia County	7.2	4	Vestas	RES America	Puget Sound Energy	Puget Sound Energy	2008
Marengo II	Columbia County	70.2	39	Vestas	RES America	PacifiCorp	PacifiCorp	2008
Goodnoe Hills	Klickitat County	94	47	REPower	enXco/Power Holdings	enXco/Power Holdings	PacifiCorp	2008
Nine Canyon III	Benton County	32.2	14	Siemens	Energy Northwest/ RES Americas	Energy Northwest	Energy Northwest	2008
White Creek Wind Power Project	Klickitat County	204.7	89	Siemens	Last Mile Electric Cooperative	Last Mile Electric Cooperative	Last Mile Electric Cooperative	2007
Marengo Wind Farm	Columbia County	140.4	78	Vestas	RES America	PacifiCorp	PacifiCorp	2007

Name	Location	Power Capacity (MW)	Units	Turbine Mfr.	Developer	Owner	Power Purchaser	Year Online
Big Horn Wind Power Project	Klickitat County	199.5	133	GE Energy	PPM Energy	Iberdrola Renewables	Modesto-Santa Clara-Redding Public Power Agency	2006
Wild Horse Wind Power Project	Kittitas County	228.6	127	Vestas	Horizon Wind Energy	Puget Sound Energy	Puget Sound Energy	2006
Hopkins Ridge Wind Farm	Columbia County	149.4	83	Vestas	RES America	Puget Sound Energy	Puget Sound Energy	2005
Nine Canyon Wind Farm, phase II	Benton County	15.6	12	Bonus	Energy Northwest	Energy Northwest	Energy Northwest	2003
Nine Canyon Wind Farm	Benton County	48.1	37	Bonus	Energy Northwest	Energy Northwest	Energy Northwest	2002
Stateline Wind Energy Project	Walla Walla County	176.88	268	Vestas	FPL Energy	FPL Energy	PPM Energy	2001

Electricity generated by a wind farm is fed into the electric power transmission network. Individual turbines are interconnected with a medium voltage (usually 34.5 kV) power collection system and communications network. At the project substation, this medium-voltage electrical current is increased in voltage with a transformer for connection to the high voltage transmission system.

B. Offshore Wind Generation

Five countries have wind turbines installed offshore, providing clean, renewable electricity: Denmark, Sweden, the United Kingdom, the Netherlands, and Ireland. Germany has approved 22 new offshore projects. The world's first offshore wind project was built in Denmark in 1991, north of the island of Lolland. The 4.9 MW project has performed well. Now more than 25 offshore projects are in operation, with others under construction or in the planning stage.

The world's largest operating offshore wind project, Horns Reef, was completed in 2003, with 80 Vestas 2.0 MW turbines totaling 160 MW of capacity.[28] A still larger offshore

[28] Danish Wind Industry Association, 2003

project, Thanet Offshore Wind project in the UK, is expected to enter service in 2009 with over 300 MW of electrical capacity.

Cape Wind, a hotly debated project near Cape Cod in Nantucket Sound, is still moving forward and could be the first U.S. offshore wind farm in operation. Still pending are approvals from state, local, and federal organizations including the Coast Guard, Department of the Interior and the Federal Aviation Administration. However, two projects planned off Long Island (Bluewater and LIPA Offshore) are close behind. NREL's goal is to lower costs to $50 per MWh by 2012, at which time it expects to utilize new 5 MW to 7 MW turbines installed in shallow water (less than 15 meters).

Offshore wind farms benefit from stronger, more stable winds, but have higher capital and operating costs. Offshore turbines may also have higher capacities than their onshore cousins due to modified gearboxes with higher rotation rates and greater sound levels than would be allowed on shore. Currently, there is no land lease fee for building wind turbines in federal waters, where all turbines for the Cape Wind project are located. The U.S. Army Corps of Engineers, the final authority for permitting, issued a largely positive Draft Environmental Impact Study for Cape Wind in 2004.[29] It reported minimal impacts on marine and bird life, as well as minimal water and noise pollution. Cape Wind filed its Final Environmental Impact Report (FEIR) in February 2007 with the Massachusetts Environmental Policy Act (MEPA) office.

In general, offshore wind power is hoped to have less community resistance, although The Alliance to Protect Nantucket Sound, an energized opposition group comprised of prominent politicians, has formed in response to Cape Wind. Greenpeace and many other environmental groups have endorsed offshore wind energy, particularly Cape Wind.[30] It is unclear what kind of impact offshore farms will have on real estate values. Onshore studies in the United Kingdom have indicated that there is an initial negative impact to residential property values near wind farms, although this impact largely disappeared two years into operations.[31] European experience suggests that a decrease in property values may be offset, at least in part, by an increased tourism industry.

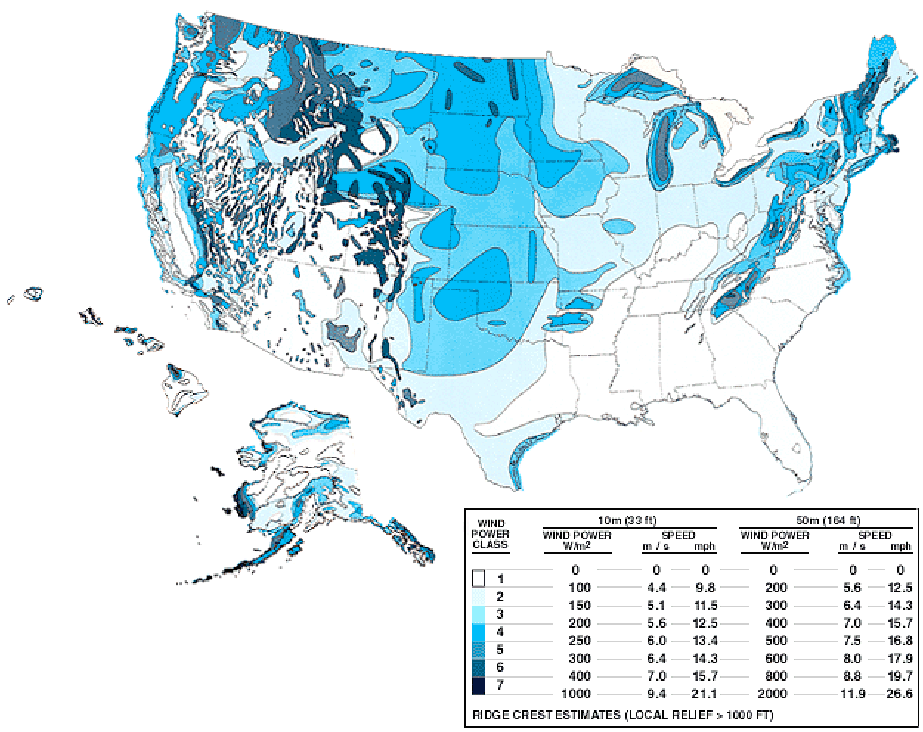
An alternative with potentially fewer citizen objections is deep water wind farms. The European Commission is funding a pilot project in which two 5 MW REPower wind

[29] Army Corp of Engineers, 2004, http://www.nae.usace.army.mil/projects/ma/ccwf/ deis.htm
[30] Cape Wind, 2005, http://www.capewind.org/article47.htm
[31] Royal Institute of Surveyors, UK, 2003, http://www.rics.org/NR/rdonlyres/66225A93-840F-49F2-8820-0EBCCC29E8A4/0/Windfarmsfinalreport.pdf

turbines were installed in the Scottish region of the North Sea at the Talisman Beatrice project in 2006.[32]

As indicated in Figure F-21 the coast of Washington state has strong winds, which may make it a potential site for offshore wind power projects. However, it remains to be determined whether such technology will become commercially viable and acceptable to the community.

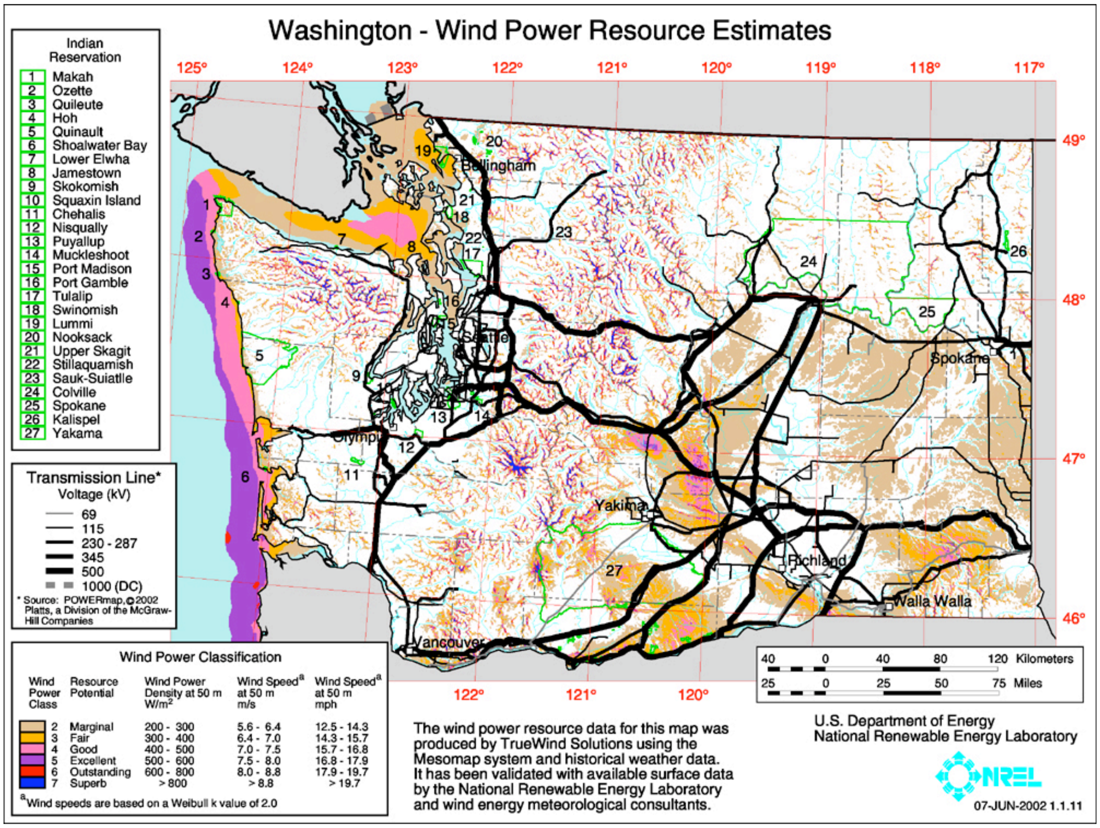
Figure F-21. Available US Wind Energy



Source: National Renewable Energy Laboratory (NREL)

[32] Royal Institute of Technology in Stockholm, http://www.kth.se/forskning/pocket/project.asp?id=22466

Figure F-22
Available Washington State Wind Energy



Source: National Renewable Energy Laboratory (NREL)

VIII. Geothermal

Worldwide geothermal generation capacity is over 9,000 MW, of which the United States has the largest national share at over 2,900 MW.[33,34] Some countries such as Iceland (over 300 MW) and the Philippines (over 1,900 MW) generate large portions of their power from geothermal sources[35], but to date the technology is inherently limited by geology. Development of geothermal power in the United States is concentrated in California, with the remaining capacity in Nevada, Hawaii and Utah. Small geothermal plants also exist in Idaho, Alaska, and New Mexico.

Geothermal energy qualifies as renewable energy under Washington's renewable portfolio standard.

Geothermal power production captures heat from inside the earth using one of four methods:

- Dry Steam Plants utilize hydrothermal steam from the earth directly in turbines. This was the first type of geothermal power generation technology, but is limited by the number of sites that offer very hot (greater than 235°C) hydrothermal fluids that are predominantly steam.[36]
- Flash Steam Plants operate similarly to dry steam plants but use low pressure tanks to vaporize hydrothermal liquids into steam. Like dry steam plants, this technology is best suited to high temperature geothermal sources (greater than 182°C).[37]
- Binary Cycle Power Plants can use lower temperature (107°C to 182°C) hydrothermal fluids to transfer energy through a heat exchanger to a fluid with a lower boiling point. This system is completely closed-loop, without even steam emissions. The majority of new geothermal installations are likely to be binary cycle systems due to emissions and the greater number of potential sites.[38]

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33 International Geothermal Energy Association, http://iga.igg.cnr.it/geoworld/geoworld.php?sub=elgen
34 Geothermal Energy Association, http://www.geo-energy.org/publications/reports/Geothermal_Update_August_7_2008_FINAL.pdf
35 IGA 2000, http://iga.igg.cnr.it/geoworld/geoworld.php?sub=elgen
36 Renewable Energy Policy Project, http://repp.org/geothermal/geothermal_brief_power_technologyandgeneration.html
37 EERE, http://www1.eere.energy.gov/geothermal/geothermal_basics.html
38 Ibid

- The United States, Japan, England, France, Germany and Belgium are testing Enhanced Geothermal or "hot dry rock" technologies.[39] These systems involve the drilling of deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation. There are small operating facilities in Germany and France. Several commercial facilities are under development in Australia, and the US Department of Energy has funded a test project in the United States.

Several factors affecting geothermal resource development are longevity and quality, plant siting, land availability and proximity to transmission lines, and equipment lead times.

Geothermal resources in the United States underwent significant exploration drilling in the 1970s, but many exploration programs were slowed or halted after the 1970s energy crisis ended. Because of the difficulty in assessing subsurface conditions without drilling, the majority of recent development has involved known resources where risks are lower.

Geothermal depletion is a concern that leads many to question whether geothermal power is truly a renewable resource. Continued aggressive use of a geothermal well can lead to temperature and pressure reductions. The Geysers complex of geothermal installations in northern California decreased in output from over 1,800 MW in the late 1980s to around 1,000 MW in 2001. Economic modeling of 20 to 30 years of production is standard.[40] In addition to resource longevity, there is the question of resource quality. Some geothermal fluids are corrosive and may contain scaling elements. Research is ongoing with heat exchanger linings and acid resistant cements. In addition, there are efforts to extract commercial products such as zinc or high purity silica from geothermal fluids to offset costs.[41] Further, although SO_x and CO_2 emissions are very low, they are both present in both dry and flash steam plants as part of the geothermal fluid.

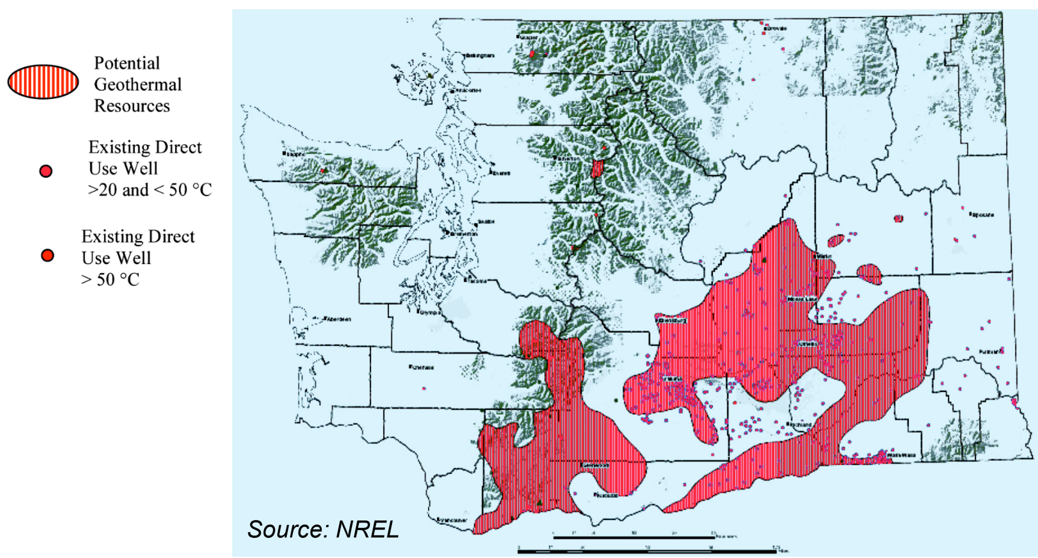
Siting geothermal plants can be difficult, as many geothermal resources in the western United States are not located close to existing transmission. Further, the majority of lands in the western United States are managed by the U.S. government, requiring a process

[39] Geothermal Education Office, 2000, http://geothermal.marin.org/pwrheat.html
[40] Geothermal.org, 2002, http://www.geothermal.org/articles/California.pdf
[41] Lawrence Livermoore National Labs, 2004, http://www.geothermal.org/DOE_presentations/BRUTON_L.PPT

for land leasing, permitting, and development. The Energy Policy Act of 2005 created a new competitive leasing process for geothermal lands, which has increased the number of leases awarded each year.

Development of geothermal resources takes 2 to 3 years, and drilling equipment availability significantly affects development timelines. There are a limited number of drill rigs capable of geothermal development in the United States, and they are in demand. Further, there is competition with the oil industry for labor, which can drive up costs.[42]

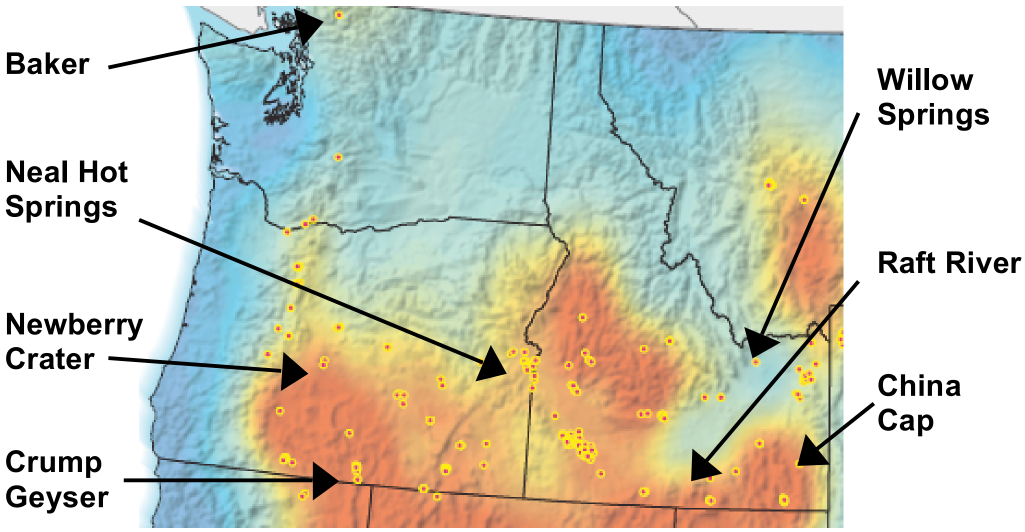
Figure F-23
Geothermal Potential in Washington



There are no active geothermal projects in Washington state, though there has been recent interest. Vulcan Power has applied for a lease in the North Cascades, and several private and public entities have been working on development assessments. Several geothermal plants are under development in Oregon, and the Raft River Plant in Idaho became operational in 2007. The plants proposed or under development in the Northwest are shown in Figure F-24.

[42] Glitnir Bank, http://docs.glitnir.is/media/files/Glitnir_USGeothermalReport.pdf

Figure F-24
Proposed or Active NW Geothermal Developments



IX. Coal

There are three principal technologies available for utilizing coal, and other solid fuels, in the production of electricity. Two of these technologies, pulverized fuel boilers and fluidized bed boilers, combust fuel to produce heat. The heat boils water to produce steam, which in turn drives a steam turbine-generator to produce electricity. When fueled with coal, these are referred to as "conventional coal" technologies. The third technology, gasification, converts any carbon-containing material into a synthesis gas (syngas) composed primarily of carbon monoxide and hydrogen. This syngas can be used to fuel the generation of electricity or steam production or as a chemical feedstock.

A. Pulverized Coal

With pulverized coal (PC) technology, the coal is ground into a fine powder that is mixed with air and blown into the boiler furnace to be burned. The resulting heat is then used to produce steam. Fuel efficiency can be improved by increasing the temperature and pressure of the steam generated in the boiler. Current designs utilize steam pressures of 2,500 psi and greater.

Supercritical boilers produce steam in excess of 3,200 psi. Such boilers were introduced in the United States in the 1970s, but were plagued by metallurgical problems due to high operating temperatures and pressures. More recently, supercritical PC units (SCPC) have been operated successfully in Europe and Japan and are re-emerging in North America. To further improve efficiency, ultra-supercritical PC units (UCPC), operating at even higher pressures, are now available.

Most coal-fired boilers operating in the United States today use PC technology. Similar boilers are also used to burn petroleum coke and other solid fuels. Boiler designs are available in a range of sizes from units producing less than 100 MW to those exceeding 1,000 MW, powered by a single PC boiler. In addition to increasing boiler efficiency with SCPC and UCPC units, equipment suppliers are improving combustion and post-combustion pollution control equipment to meet increasingly stringent emission reduction requirements.

B. Fluidized Bed

Fluidized bed (FB) technologies mix coal and an inert bed material, such as sand, in a combustor or boiler. The mixture of particles is suspended by an upward flow of air and burns producing heat to generate steam. Increasing the air flow affects the fluid-like flow of the particles, resulting in a fixed, bubbling or circulating bed condition. Limestone may be added to the bed material to help capture sulfurous gases that are released as the coal is burned. High heat transfer in the boiler occurs with lower combustion temperatures, resulting in lower levels of NOx formation than in PC boilers. Post-combustion technologies are also used to further lower air emissions.

FB boilers can burn a wide variety of solid fuels in addition to coal and petroleum coke. Single FB boilers are available in sizes up to 600 MWe and the first super-critical FB boiler (460 MWe) just began operation in Poland. In 2001, the Northside Repowering Project of the Jacksonville (FL) Electric Authority replaced two boilers fueled by oil or gas with two circulating fluidized bed (CFB) boilers fueled by coal. At approximately 300 MW each, these are the two largest CFB boilers in the United States.

The pressurized fluidized bed combustion (PFBC) boiler utilizes fluidized bed technology at elevated operating pressures to produce heat for steam production and hot pressurized exhaust gases that may be used to drive a combustion turbine. In the early 1990s, Ohio Edison built a demonstration PFBC plant to power a 55 MW steam turbine[43] and a 15 MW combustion turbine. Although the PFBC offers the promise of higher energy production efficiency, there has been no further commercial development of PFBC technology in the United States.

C. Gasification

Coal and other solid or waste fuels have been gasified to create liquid or gaseous fuels for more than 100 years. In the 1800s, crude coal gasification provided gas for lighting streets and homes. During World War II, Germany gasified coal to produce fuel for airplanes and tanks. South Africa has gasified its indigenous coal supply to create liquid and gas fuels since the 1950s, and these plants continue to operate today.

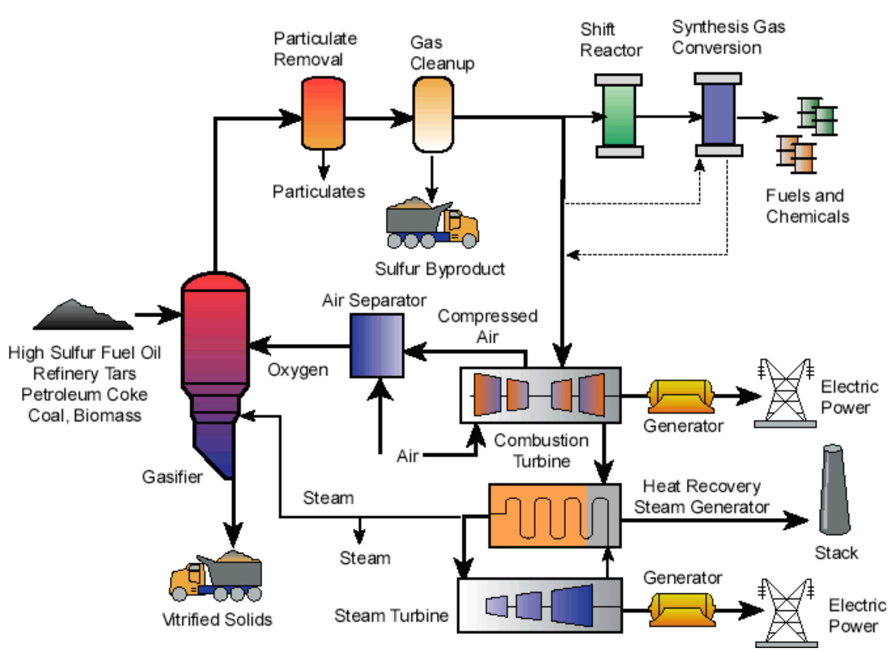
[43] The US DOE funded 35% of the cost of this project.

Coal gasification uses a partial oxidation process to produce a low to medium Btu (100 to 450 Btu per SCF) syngas, which can be fired in a boiler to produce steam to drive a steam turbine generator or may be substituted for natural gas in combustion turbines. In the partial oxidation reaction, there is insufficient oxygen present to convert all of the carbon in the fuel to carbon dioxide. When available oxygen is reduced, less heat is released from the coal, and gaseous products appear. These products include hydrogen, carbon monoxide, and methane (CH4), all of which contain potential chemical energy.

Integrated Gasification Combined Cycle (IGCC)

The integrated gasification combined cycle process teams a gasifier with combined cycle equipment. While the extent of integration may vary, depending upon the gasification and combustion turbine equipment selected, IGCC generally refers to a model in which syngas from the gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier. Additionally, heat from the gasifier is coupled with exhaust from the combustion turbine to generate steam, which is used to drive a steam turbine-generator to produce additional electricity. This design has been widely used with natural gas and distillate fuels since the 1980s.

Figure F-25
The Coal Gasification Process



Source: Gasification Technologies Council (www.gasification.org)

The combination of coal gasification and combustion turbine technologies was first successfully demonstrated in the United States for electric power production on a commercial scale at the 100 MW Cool Water Demonstration Project in Daggett, Calif. This plant was operated successfully by Texaco, Bechtel, General Electric, and EPRI from 1984 to 1989 and was then decommissioned. A number of additional demonstration projects were developed in the 1980s and 1990s.

Commercial Availability

To date, the application of gasification for electric power production using IGCC has been limited to demonstration projects. While there are a number of vendors and technologies for gasification, the experience with coal is limited. The table below identifies the existing gasification plants in the United States, the products produced, and the fuel utilized.

Figure F-26
Existing Gasification Plants in the U.S.

Plant Name	Location	Year of Initial Operation	Main Product Produced	Fuel Utilized
Houston Oxochemicals Plant	*Houston, TX*	*1977*	*Chemicals*	*Gas*
Baton Rouge Oxochemicals Plant	*Baton Rouge, LA*	*1978*	*Chemicals*	*Petroleum*
LaPorte Syngas Plant	*Deer Park, TX*	*1979*	*Chemicals*	*Gas*
Hoechst Oxochemicals Plant	*Bay City, TX*	*1979*	*Chemicals*	*Petroleum*
68Kingsport Integrated Coal Gasification Facility	*Kingsport, TN*	*1983*	*Chemicals*	*Coal*
Sunoco Oxochemicals Plant	*Texas*	*1983*	*Chemicals*	*Gas*
Texas City Dow Syngas Plant	*Texas City, TX*	*1983*	*Chemicals*	
Great Plains Synfuels Plant	*Bismarck, ND*	*1984*	*Gaseous fuels*	*Coal*
Convent H2 Plant	*Convent, LA*	*1984*	*Chemicals*	*Petroleum*
Wabash River Energy Ltd.	*West Terre Haute, IN*	*1995*	*Power*	*Petcoke*
Taft Syngas Plant	*Taft, LA*	*1995*	*Chemicals*	*Gas*
LaPorte Syngas Plant	*LaPorte, TX*	*1996*	*Chemicals*	*Gas*

Plant Name	Location	Year of Initial Operation	Main Product Produced	Fuel Utilized
Texas City Praxair Syngas Plant	Texas City, TX	1996	Chemicals	Gas
Polk County IGCC Project	Mulberry, FL	1996	Power	Coal
Oxochemicals Plant	Texas	1998	Chemicals	Gas
Coffeyville Syngas Plant	Coffeyville, KS	2000	Chemicals	Petcoke
Baytown Syngas Plant	Baytown, TX	2000	Gaseous fuels	Petroleum
Delaware Clean Energy Cogeneration Project	Delaware City, DE	2002	Steam & Power	Petcoke
Longview Gasification Plant	Longview, TX	2002	Chemicals	Gas

Source: World Gasification Database; Gasification Technologies Council

To encourage commercialization of IGCC, major technology licensors have formed "alliances" with engineering and construction firms to provide design and construction on a turnkey basis. These alliances may provide limited guarantees of cost and schedule and initial operating performance. To begin development, a buyer must select a design type and provide detailed fuel specifications and proceed with a Front End Engineering Design (FEED) study to develop the design envelope. Each alliance requires a specific FEED study before negotiating the contract and guarantees. FEED studies are currently estimated to cost more than $20 million for each fuel specification and do not ensure the technology will be economic.

There are currently two operating, commercial-size, coal-based IGCC power plants in the United States. The 262 MWe[44] Wabash River IGCC repowering project in Indiana commenced operation in 1995[45]. Tampa Electric's 250 MWe Polk Power Station IGCC project in Florida commenced operation in 1996[46]. Additionally, there are two operating, commercial-sized IGCC power plants in Europe, and three gasification projects utilizing coal or petcoke in the United States which produce feedstocks for chemical production.

[44] MWe is the abbreviation for megawatt electric. In this case MWe is used to indicate that the gasified coal is used to fuel a gas turbine, thus producing electric power.
[45] The Wabash River IGCC project uses the E-Gas gasification technology, which was acquired by ConocoPhillips in 2003.
[46] The Polk Power Station uses the Texaco gasification technology, which was acquired by GE Energy in 2004.

The increase in cost and price volatility of natural gas in the mid-2000s generated a renewed interest in IGCC for electric power production. More recently, this interest has waned, as it has with other coal-based power projects, due to the rapid increase in the cost of construction materials and uncertainty over greenhouse gas control regulations.

D. Estimated Cost of Current Coal Technologies[47]

There is uncertainty within the electric power industry regarding the costs and reliability of IGCC technology versus "conventional coal combustion" technologies. The installed cost of a power island using a pulverized coal (PC) boiler ranges between $2,600 per KW to $3,200 per KW in current dollars. Circulating fluidized bed (CFB) plants are in the same range; however, larger plants (over 250 MW) must be built in modules due to the size limits of available CFB boilers. IGCC plants are estimated to cost 15% to 25% more to construct than PC units of equal size.

Further, the gasification train of IGCC projects is less reliable than the power generation equipment of PC and atmospheric FB boilers. Without a spare gasifier, the equivalent availability of an IGCC unit is projected to be 85%, while new PC units commonly attain over 90% equivalent availability. The reliability of the electricity-producing combined cycle plant can be increased to over 90% if the facility is designed to use both syngas and natural gas.

IGCC vendors are under pressure to reduce both the cost and down-time of their products. In time, it is expected that IGCC unit costs will become similar to PC unit costs as more plants are built. IGCC plants can also be modular, in units of 250 MW to 300 MW, to take advantage of existing combustion turbine technology. Because of the equipment redundancy of modular CFB or IGCC plants, their reliability may be higher than that of a single boiler, single turbine PC unit.

The cost of a new coal plant is highly affected by siting factors: availability of electric transmission interconnection, availability of water and rail, and other infrastructure. Such costs may eliminate the cost differences between technologies. The cost of development, permitting and preliminary design can range from $20 million to over $50 million without

[47]This discussion is based on costs related to permitting, planning, design, construction and commissioning of the "power island" which begins at the point of receipt of the coal fuel at the plant site and ends with the generator step-up transformers before connection of the plant to a substation and the high voltage transmission system. The cost of interest during construction, or AFUDC, is not included.

assurance that the plant can be built.

E. Environmental Climate

Major electric generating plants are subject to federal and state permitting laws and regulations covering air and water emissions, water use, waste management and pollution prevention. Additionally, state and local land use and zoning laws may govern site selection, and may also affect other plant siting issues, economic impacts or operating requirements. In the Pacific Northwest, the states of Washington, Oregon and Montana have created special regulation to manage the process of permitting major electric generating plants.

The Federal Clean Air Act applies to any electric generating facility and covers six Criteria Pollutants and more than 180 Hazardous Air Pollutants (HAPs). Of the HAPs, it is usually only Mercury and nickel[48] that affect plant permitting and require specific control devices as part of the plant design, though many others must be analyzed during the permitting process. The EPA enforces the Clean Air Act and has set National Ambient Air Quality Standards (NAAQS) for six Criteria Pollutants: Sulfur Oxides, Nitrogen Dioxide, Particulate Matter, Ozone, Carbon Monoxide and Lead.

The federal Clean Air Mercury Rule (CAMR), which required that existing and new coal plants reduce at least 30% of their mercury emissions by 2010, and at least 70% by 2018, has been vacated by a Federal District Court. This rule was designed to permanently cap and reduce mercury emissions from coal-fired power plants. To date, several states, including Washington and Montana, have enacted mercury control rules.

Additionally, while the federal government has not addressed the issue of greenhouse gases (GHGs), states and local governments have been taking action. Washington state is a member of the Western Climate Initiative, which was launched in February 2007. The Western Climate Initiative is a collaboration of seven U.S. governors and four Canadian premiers.

Carbon dioxide (CO_2) emissions from power generators are not currently regulated at the federal level. Washington has adopted a limit on carbon dioxide emissions from new, baseload power plants and requires mitigation of CO_2 emissions. See the Regulatory and

[48] Mercury and nickel are the subjects of ongoing EPA rulemaking. A number of individual states have enacted limits on mercury emissions.

Policy Activity chapter of the Environmental Concerns appendix for more information about possible future legislation.

New power plants (and major modifications to existing power plants) must employ Best Available Control Technology (BACT) and meet the New Source Performance Standards (NSPS) established by the EPA before receiving a permit to begin construction. What constitutes BACT is a function of the equipment and fuel to be utilized and the local and regional air quality. BACT is determined on a case-by-case basis, taking into account energy, environmental and economic impacts, and costs. Competition among equipment vendors, combined with pressure from plant owners and regulators, have caused the BACT process to result in significant reductions in permitted emission levels. At present, the rate of change in BACT for gasification is far more rapid than for PC and FB units. Current EPA regulations and policy do not require that IGCC be included when performing BACT analyses for new PC and FB units; however, the permitting processes in many states do require such comparison. In February 2006, EPA revised its regulations to clarify that combustion turbines and combined cycle plants that receive 75% or more of their heat input from synthetic coal gas are subject to the same rules as utility steam boilers (40 CFR 60, Subpart Da) rather than the rules (Subpart KKKK) covering combustion turbines.

For more information about local and federal environmental regulations and related environmental issues, see Chapter 2, Planning Environment, and the Environmental Concerns Appendix, where PSE's Greenhouse Gas Policy can be found.

F. Emission Control Technologies

A significant difference between PC, FB and IGCC technologies is how, where in the process cycle, and how effectively Criteria Pollutants and HAPs are controlled. Conventional coal plants built recently include specialized, highly efficient pollution control equipment to reduce the emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury, and particulates. Many older plants have also added advanced pollution control devices and further federal legislation and EPA action is expected to significantly increase the number of existing plants with retrofitted pollution control equipment.

IGCC vendors claim greater capture rates for sulfur dioxide, nitrogen oxides and particulates because pollutant removal is performed prior to the introduction of the syngas fuel into the combustion turbine. In PC and FB boilers, these pollutants are captured during or after coal combustion. Vendors of conventional boilers have responded to these claims by continuing to offer equipment designs with lower emission rates.

The following discussion focuses on the typical pollutants and HAPs that must be considered in converting coal to electricity. Because of the wide variety of proprietary gasification system designs, the process flow and equipment described may vary somewhat in configuration; however, all use the same basic steps.

Particulate Matter

Particulate matter refers to inorganic impurities in the coal in the form of fine ash.

Figure F-27
Particulate Matter Controls

PC and FB units	Particulate matter is captured using an electro-static precipitator (ESP) or a fabric filter (FF), also called a bag-house, to clean flue gases after they exit the boilers. ESPs were the first control devices applied to existing PC boilers. ESPs or FFs are used in the construction of all new PC and FB designs. Current performance requirements for ESPs and FFs are 0.02 lbs per MMBtu of heat input (about 0.2 lbs per MWh) or less in flue gases released to the atmosphere.
IGCC	Particulates are separated by gravity from the raw syngas in the gasifier. They exit the gasifier as slag or other similar solids. Additional removal of fine particulates takes place in candle filters in the raw syngas clean-up equipment between the gasifier and the combustion turbine. Current performance requirements are less than 0.01 Lbs per MMBtu or 0.1 Lbs. per MWh.

Sulfur Dioxide (SO_2)

All coal contains sulfur. It ranges from less than 1% by weight in some western U.S. coals to more than 6% in some mid-western coals. Petroleum coke, the waste product from the refining process, contains most of the sulfur from the original crude oil supply, which may be 4% by weight or more.

Figure F-28
Sulfur Dioxide Controls

PC units	Scrubbers are employed downstream of the boiler to mix an alkaline material, such as lime, with boiler exhaust gases to capture sulfur compounds. Some older scrubber designs also capture particulate matter (fly ash), eliminating the need for a separate ESP or FF. Scrubber designs fall into two broad categories: dry and wet. Dry scrubbers: Flue gas heat evaporates water media used to supply the alkaline material, leaving a dry alkali-sulfur compound. Particulate control equipment, normally placed after the scrubber, captures this dry product. Wet scrubbers: Particulate control occurs ahead of the scrubber. In such case, the alkali-sulfur product is a slurry with a chemical composition similar to natural gypsum. If transportation cost can be minimized, the scrubber product can be dried and sold for wall board manufacture.
FB units	Most FB units use an alkaline material as part of the bed. Before leaving the boiler, the alkali captures the sulfurous gas released during combustion and is then captured by the particulate control equipment, normally an FF. A polishing scrubber, similar to the main scrubbers on a PC unit, can be added to further reduce the amount of sulfur that leaves the stack in flue gases.
IGCC	The raw syngas that leaves the gasifier contains carbonyl sulfide (COS), which is converted to hydrogen sulfide (H2S) through electrolysis. Acid gas clean-up equipment then removes the H2S. Between the gasifier and the sulfur removal, the syngas is cooled in heat exchangers that use recovered heat to generate additional steam for the steam turbine. A sulfur recovery system may be added after the acid gas clean-up to recover sulfur as a salable by-product, either as elemental sulfur or as sulfuric acid.

Current SO_2 performance requirements for both PC and FB units require removal of more than 99% of the sulfur in the coal, yielding an emission level of 0.1 lbs per MMBtu (about 1 lbs per MWh) or less in the flue gases released into the atmosphere.

Current SO_2 performance requirements for gasification systems require removal of 99.5% of the sulfur in the coal, yielding an emission level as low as 0.03 lbs per MMBtu (less than 0.3 lbs per MWh) or less in the flue gases released into the atmosphere. In order to effectively capture mercury, the SO_2 emission level must be below 0.01 lbs per MMBtu before reaching the mercury absorber equipment. This requires use of a proprietary acid gas clean-up process, such as Selexol.

Nitrogen Oxides

Figure F-29
Nitrogen Oxide Controls

PC units	Nitrogen oxides (NOx) can be reduced in the PC boiler during combustion of the coal using Low NOx Burners, which reduce combustion temperatures, thereby affecting the amount of NOx produced. Over-fire air is used with Low NOx Burners to further cool the fireball in the furnace and reduce NOx production. Ammonia (NH3) can be injected into the PC boiler flue gas as it leaves the boiler to reduce NOx. A catalyst can be employed to aid in the chemical reaction between NH3 and NOx, that results in formation of water (H2O) and elemental nitrogen (N2). When a catalyst is used, this is called Selective Catalytic Reduction (SCR). Without a catalyst, it is known as Selective Non-Catalytic Reduction (SNCR).
FB units	In FB boilers, NOx is reduced in the combustor by keeping the combustion temperatures lower and may be further reduced by the addition of SCR or SNCR technology in the flue gas stream after the boiler.
IGCC	There is no NOx produced in the oxygen blown gasification process. The only NOx production occurs during the syngas combustion in the combustion turbine. NOx emission levels below 0.03 Lbs per MMBtu can be obtained with normal combustion practices using water and N2 (from the air separation plant) injection into the combustors of the combustion turbine with the syngas. Even lower levels, down to 0.01 Lbs per MMBtu or lower may be obtained by addition of SCR equipment to the combustion turbine exhaust. This requires extremely low levels of SO2 in the syngas stream to the combustion turbine.

Current NOx performance requirements for both PC and FB units is an emission level of 0.07 Lbs per MMBtu (about 0.7 Lbs per MWh) or less in the flue gases released to the atmosphere.

IGCC projects currently being permitted are being asked to review whether use of SCR equipment is BACT.

Mercury

As previously discussed, the regulations in Washington, Montana and a number of other states require that all coal-burning power plants reduce their mercury emissions. The past five years have seen much research and demonstration of sorbent injection and other techniques to remove mercury from PC and FB unit flue gasses, but no single technology has been confirmed to provide long-term mercury removal for all types of coal and all boiler designs.

The Tennessee Eastman coal gasification facility has demonstrated success in removing mercury to non-detectable levels using sorbent beds during its syngas clean-up processes. The plant has been in operation generating chemical feedstocks since 1984.

This sorbent bed technology should facilitate mercury removal at levels high enough to meet existing state requirements.

Carbon Dioxide

Although carbon dioxide (CO_2) is not currently regulated as an air pollutant, there is keen interest in developing technologies to economically remove it from flue gases. Washington requires mitigation of carbon dioxide emissions from new power plants and limits the emission of CO2 from new, base-load power plants. The technology for carbon dioxide capture in the gas clean-up portion of the IGCC is clearly more developed than is post-combustion capture of carbon dioxide from either a PC or FB boiler. However, effective methods of permanent sequestration, other than injection for enhanced oil recovery in specific locations, is not commercially developed and readily accessible. A July 2006 study for the EPA found that adding carbon capture technology to various IGCC designs increased the cost of electricity by 25% to 40%. The cost of energy from a supercritical PC unit was estimated to increase by as much as 65%. Not only does carbon capture entail the large capital and operating costs of additional equipment, it also significantly increases parasitic plant energy use. This and other studies caution that IGCC design and cost information is more sensitive to both the specifics of the site and the type of coal to be used than a PC unit. The limited development of carbon dioxide sequestration technologies and sites, however, limits the current ability of both IGCC and conventional coal technologies to “solve” the GHG problem.

Carbon capture

Amine-based CO2 capture systems have been demonstrated on a limited basis in flue gas slipstreams of PC and FB systems. Research is also underway to produce more cost-effective systems using ammonia-based or other processes, but no systems are currently available for full-scale CO2 removal from PC or FB units. Furthermore, preliminary estimates indicate these systems could increase the cost of electricity by 60% or more.

The use of “oxy-fuel” combustion practices, which use an air separation plant to deliver O_2 rather than air for the combustion process, is being developed for PC units. This could be used in new designs or retro-fit to existing PC units. Using oxy-fuel techniques yields a flue gas stream of nearly pure CO_2, which eliminates the need to separate the CO_2 from the other gases, primarily nitrogen, in the flue gas stream. Other than pilot projects, this technology has yet to be demonstrated, and no solid cost estimates are available.

Separation of CO_2 in the gasification process has been demonstrated using the water shift reaction to convert carbon monoxide (CO) and water into CO_2 and elemental hydrogen (H_2) as the fuel gas. However, manufacturers are researching and developing combustion turbines that can utilize H_2, though these are not yet commercially available.

Carbon Sequestration

Terrestrial carbon sequestration utilizes natural methods for returning carbon to the soil and plants at the surface level. Soil contains CO_2, which is sequestered by the plants. But overgrazing reduces the plants' ability to perform their function. Improved pasture management can increase the amount of CO_2 in the soil. Crops also sequester carbon in the soil, but the tilling process releases it back into the atmosphere. Agriculture practices that reduce tilling have been shown to increase the level of carbon in the soil. Afforestation is the growing of trees that will capture carbon and hold it until the wood decomposes or is combusted. Hence, long term management of afforestation projects is necessary to insure that the carbon stays sequestered. Overall, while agriculture is responsible for a small portion of America's contribution to climate change, it can still be part of the solution.

Geologic sequestration involves pumping CO_2 deep into the ground, where it reacts with the rocks to form an inert compound. There are numerous opportunities for carbon capture and sequestration (CCS). For example, for 30 years oil companies have practiced "enhanced oil recovery," whereby CO_2 is injected into the wells to improve the recovery of oil. In the Northwest, testing is currently underway with wells drilled deep into rock formations. The pumped CO_2, in an supercritical state, reacts with the mafic rock (basalt) to form the inert calcite. The economic cost of the geologic sequestration has not been determined at this time; however, significant infrastructure investments are necessary in order to accomplish CCS on a large scale.

PSE participates in the Big Sky Carbon Sequestration Partnership based in Bozeman, Mont., which is investigating numerous sequestration technologies for effectiveness and cost[49] and is following research and sequestration demonstrations activities of the Pacific Northwest National Laboratory operated by Battelle.

[49] Big Sky Carbon Partnership, Montana State University, Bozeman, MT; http://www.bigskyco2.org/

Water Use

Because IGCC units utilize both gas turbines and steam turbines for electricity production, consumptive water use is typically about one-third less than that of similarly-sized PC or FB units. IGCC units use smaller steam turbines, requiring less condenser cooling water.

Solid Wastes

PC, FB and IGCC units all produce solid waste products that can be marketed or disposed of as solid waste. The types of products produced vary by technology and design. The ability to market these products is largely a function of plant location and bulk material transportation costs.

X. Natural Gas

A. Combined-cycle Combustion Turbines

A combined-cycle combustion turbine (CCCT) power plant consists of one or more gas turbine generators (GTG) equipped with heat recovery steam generators (HRSG) to capture heat from the gas turbine exhaust. Steam produced in the HRSG powers a steam turbine generator (STG) to produce additional electric power. Use of the otherwise wasted heat in the turbine exhaust gas results in high thermal efficiency compared to other combustion based technologies. CCCT plants currently entering service can convert about 50% of the chemical energy of natural gas into electricity.

A single-train CCCT plant consists of one GTG, HRSG, and STG (or 1x1 configuration). Using “F-class” combustion turbines - the most common technology in use for large CCCT plants - this configuration can produce about 270 MW of capacity. Plants can also be configured using two or even three GTGs and a HRSG feeding a single, proportionally larger STG. Larger plant sizes result in economies of scale for construction and operation, and designs using multiple GTGs provide improved part-load efficiency. A 2x1 configuration using F-class technology will produce about 540 MW of capacity. Other plant components include a switchyard for electrical interconnection, cooling towers for cooling the STG condenser, a water treatment facility, and control and maintenance facilities.

Additional generating capacity can be obtained by use of various power augmentation features, including inlet air chilling and duct firing (direct combustion of natural gas in the HRSG). For example, an additional 20 MW to 50 MW can be gained from a single-train plant by use of duct firing. Though the incremental thermal efficiency of duct firing is lower than that of the base CCCT plant, the incremental cost is low and the additional electrical output can be valuable during peak load periods.

GTGs can operate on either gaseous or liquid fuels. Pipeline natural gas is the fuel of choice because of historically low and relatively stable prices, deliverability, and low air emissions. Distillate fuel oil can be used as a backup fuel.

Because of high thermal efficiency, low initial cost, high reliability, relatively low gas prices, and low air emissions, CCCTs have been the new resource of choice for bulk power generation for well over a decade. Other attractive features include significant operational flexibility, the availability of relatively inexpensive power augmentation for peak period operation, and relatively low carbon dioxide production.

Proximity to natural gas mainlines and high voltage transmission is the key factor affecting the siting of new CCCT plants. Secondary factors include water availability, ambient air quality, and elevation.

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of any power generation technology using fossil fuel. The carbon dioxide production of a CCCT plant on a unit output basis is much lower than that of other fossil fuel technologies.

B. Peaking Power Plants[50]

Peaking power plants, also known as peaker plants, are power plants that generally run only when there is a high demand, known as peak demand, for electricity or a requirement to maintain system operating reserves. In contrast, base load power plants operate continuously, stopping only for maintenance or unexpected outages. Intermediate plants operate between these extremes, curtailing their output in periods of low demand, such as during the night. Base load and intermediate plants are used preferentially to meet electrical demand because the lower efficiencies of peaker plants make them more expensive to operate.

Peaker plants can operate many hours a day, or as little as a few hours per year, depending on the loading condition of the region's electrical grid. It is expensive to build an efficient power plant, so if a peaker plant is only going to be run for a short and variable time, it does not make economic sense to make it as efficient as a base load power plant. In addition, the equipment and fuels used in base load plants are often unsuitable for use in peaker plants because the fluctuating conditions would severely

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[50] References for peaking power plant information
http://www.simplecyclepowerplants.com/
http://en.wikipedia.org/wiki/Gas_turbine
http://www.energysolutionscenter.org/DistGen/Tutorial/TutorialFrameSet.htm
http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf
http://www.energysolutionscenter.org/DistGen/Tutorial/TutorialFrameSet.htm
http://en.wikipedia.org/wiki/Reciprocating_engine
http://www.energy.ca.gov/distgen/equipment/reciprocating_engines/reciprocating_engines.html
http://www.cat.com/cda/layout?m=37508&x=7
http://www.eere.energy.gov/de/gas_fired/
http://www.wartsila.com/,en,solutions,applicationdetail,application,F00F72F1-9579-47E6-B6BD-60A0E42943A4,B0B76B09-FEAF-497D-9D59-BA2EC30AFB1E,,.htm

strain the equipment. For these reasons, nuclear, geothermal, waste-to-energy, coal and biomass plants are rarely, if ever, operated as peaker plants.

Peaker plants are generally gas turbines that burn natural gas. A few of them burn distillate fuel, but their use is limited since distillate fuel is usually more expensive than natural gas. However, many peaker plants are able to use distillate fuel as a backup. The thermodynamic efficiency of gas turbine peaker power plants ranges from 20% to 40%, with about 30% to 35% being average for a new plant. The most efficient gas turbine plants are generally used for load cycling, cogeneration projects, or are intended to be operated for longer periods than usual. Reciprocating engines are sometimes used for smaller peaker plants.

C. Simple Cycle Combustion Turbines (SCCT)

Simple cycle combustion turbines in the power industry require smaller capital investment than coal, nuclear or even combined cycle natural gas plants and can be designed to generate both small and large amounts of power. Also, the actual construction process can take as little as several weeks to a few months, compared to years for base load power plants. Their other main advantage is the ability to be turned on and off within minutes, supplying power during peak demand. Since they are less efficient than combined cycle plants, they are usually used as peaking power plants, which operate anywhere from several hours per day to a couple dozen hours per year, depending on the electricity demand and the generating capacity of the region. In areas with a shortage of base load and load following power plant capacity, a gas turbine power plant may regularly operate during most hours of the day and even into the evening. A typical large simple cycle combustion turbine may produce 75 MW to 180 MW of power and have 35% to 40% thermal efficiency. The most efficient turbines have reached 46% efficiency.

The modern power combustion turbine is a high-technology package that is comprised of a compressor, combustor, power turbine, and generator. In a combustion turbine, a large volume of air is compressed to high pressure in a multistage compressor. Fuel is then added to the high-pressure air and combusted. The combustion gases from the combustion chambers power an axial turbine that drives the compressor and the generator. In this way, the combustion gases in a combustion turbine power the turbine directly, rather than requiring heat transfer to a water/steam cycle to power a steam turbine, as in the steam plant. The latest combustion turbine designs use a turbine inlet temperature of 1,500°C (2,730°F) and compression ratios as high as 30:1 (for aeroderivatives) giving thermal efficiencies of 35% or more for a simple-cycle combustion turbine.

D. Reciprocating Engine Systems

Reciprocating engines are piston-driven electrical power generation systems ranging from a few kilowatts to over 15 MW. Reciprocating engine technology has improved dramatically over the past three decades because of economic and environmental pressures for power density improvements (more output per unit of engine displacement), increased fuel efficiency, and reduced emissions.

The reciprocating, or piston-driven, engine is a widespread and well-known technology. Also called internal combustion engines, reciprocating engines require fuel, air, compression, and a combustion source to function. Depending on the ignition source, they generally fall into two categories: (1) spark-ignited engines, typically fueled by gasoline or natural gas, and (2) compression-ignited engines, typically fueled by diesel oil fuel.

Almost all engines used for power generation are four-stroke and operate in four cycles (or stokes). The four-stroke, spark-ignited reciprocating engine has intake, compression, power, and exhaust cycles. In the intake phase, as the piston moves down in its cylinder, the intake valve opens, and the upper portion of the cylinder fills with fuel and air. When the piston returns upward in the compression cycle, the spark plug emits a spark to ignite the fuel-air mixture. This controlled reaction, or "burn," forces the piston down, thereby turning the crank shaft and producing power. In the exhaust phase, the piston moves back up to its original position, and the spent mixture is expelled through the open exhaust valve.

The compression-ignition engine operates in the same manner, except the introduction of diesel fuel at an exact instant ignites in an area of highly compressed air-fuel mixture at the top of the piston. In diesel units, the air and fuel are introduced separately with fuel injected after the air is compressed by the piston in the engine. As the piston nears the top of its movement, a spark is produced that ignites the mixture (in most diesel engines, the mixture is ignited by the compression alone).

Dual fuel engines use a small amount of diesel pilot fuel in lieu of a spark to initiate combustion of the primarily natural gas fuel. The pressure of the hot, combusted gases drives the piston down the cylinder. Energy in the moving piston is translated to rotational energy by a crankshaft. As the piston reaches the bottom of its stroke, the exhaust valve opens and the exhaust is expelled from the cylinder by the rising piston.

Commercially available reciprocating engines for power generation range from 0.5 kW to 16.5 MW. Reciprocating engines can be used in a variety of applications because of their small size, low unit cost, and useful thermal output. They offer moderate capital cost, easy start-up, proven reliability, good load-following characteristics, and heat recovery potential. Possible applications for reciprocating engines include continuous or prime power generation, peak shaving, backup power, premium power, remote power, standby power, and mechanical drive use. When properly treated, the engines can run on fuel generated by waste treatment (methane) and other biofuels.

XI. Nuclear

A nuclear power plant (NPP) is a thermal power station in which the heat source is one or more nuclear reactors. Nuclear power is the controlled use of the nuclear fission reaction to release energy for work including propulsion, heat, and the generation of electricity. Nuclear energy is produced when a fissile material, such as uranium-235 (U^{235}), is concentrated such that nuclear fission takes place in a controlled chain reaction and creates heat—which is used to boil water, produce steam, and drive a steam turbine to generate electricity[51].

Nuclear fuel production for light water reactors begins with concentrating the U^{235} fraction of natural uranium to the desired enrichment. The enriched uranium is reacted with oxygen to produce uranium oxide. This is fabricated into pellets, which are then stacked and sealed into zirconium tubes to form a fuel rod. Fuel rods are assembled into fuel assemblies - bundles of rods arranged to accommodate neutron absorbing control rods and to facilitate removal of the heat produced by the fission process. Nuclear fuel is a highly concentrated and readily transportable form of energy, freeing nuclear power plants from fuel-related geographic constraints[52].

Operating nuclear units in the United States are based on light water reactor technology developed in the 1950s. Future nuclear plants are expected to use advanced designs employing passively operated safety systems and factory-assembled standardized modular components. These features are expected to result in improved safety, reduced cost and greater reliability. Though preliminary engineering is complete, construction and operation of a demonstration project is required before the technology can be considered commercial. Electricity industry interest in participating in one or more commercial-scale demonstrations of advanced technology is increasing. But even if demonstration plant development moves ahead in the next several years, lead times are such that advanced technology is unlikely to be fully commercial until about 2015. This suggests the earliest operation of fully commercial advanced plants would be around 2020. Also needed for public acceptance of new nuclear development is a fully operational spent nuclear fuel disposal system. Though spent fuel disposal technology is available and the Yucca Mountain site is under development, the timing of commercial operation remains uncertain.

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[51] http://en.wikipedia.org/wiki/Nuclear_power
[52] Northwest Power Planning Council

Nuclear plants could be attractive under conditions of sustained high natural gas prices and aggressive greenhouse gas control. Other factors favoring nuclear generation would be failure to develop economic means of reducing or sequestering the CO2 production of coal based generation, and difficulty expanding transmission to access new wind or coal resources.

Nuclear energy uses an abundant, widely distributed fuel, and mitigates the greenhouse effect if used to replace fossil-fuel-derived electricity. Lately, there has been renewed interest in nuclear energy from national governments due to economic and environmental concerns. Other reasons for interest include increased oil prices, new passively safe designs of plants, and the low emission rate of greenhouse gas.

Nuclear power plants are base load stations, which work best when the power output is constant (although boiling water reactors can come down to half power at night). Their units range in power from about 40 MW to over 1,200 MW. New units under construction in 2005 are typically in the range 600 MW to 1,200 MW. As of 2006, new nuclear power plants are under construction in several Asian countries, as well as in Argentina, Russia, Finland, Bulgaria, Ukraine, and Romania.

Nuclear power is highly controversial, enough so that the building of new commercial nuclear power plants in the United States has ceased - at least temporarily. Under recent legislation intended to jump-start development, Congress is offering more than $8 billion in subsidies and loan guarantees for the first few new plants that get built. Constellation Energy Inc. has publicly identified two sites for development. A consortium of utilities called NuStart Energy Development LLC is in the application and development process for two new plants. Also, Dominion Resources Inc. and Southern Company are each considering new plants.[53]

Almost all the advantages and disadvantages of commercial nuclear power are disputed in some degree by the advocates for and against nuclear power. The use of nuclear power is controversial because of the problem of storing radioactive waste for indefinite periods, the potential for possibly severe radioactive contamination by accident or sabotage, and the possibility that its use in some countries could lead to the proliferation of nuclear weapons. Proponents believe that these risks are small and can be further reduced by the technology in the new reactors. Disposal of spent fuel and other nuclear waste is claimed by some as an advantage of nuclear power, claiming that the waste is

[53] "Power Producers Rush to Secure Nuclear Sites: First to Develop Plans Could Tap $8 Billion In Federal Subsidies" WSJ 1/29/2007

small in quantity compared to that generated by competing technologies, and the cost of disposal small compared to the value of the power produced. Others list it as a disadvantage, claiming that the environment cannot be adequately protected from the risk of future leakages from long-term storage.

The cost benefits of nuclear power are also in dispute. It is generally agreed that the capital costs of nuclear power are high and the cost of the necessary fuel is low compared to other fuel sources. Proponents claim that nuclear power has low running costs, and opponents claim that the numerous safety systems required significantly increase operating costs.

At the end of 2008, 438 reactors in 30 countries were in operation, and another 44 reactors were under construction. Even so, the prospects for growth and expansion of nuclear power depend on several challenges being met[54], including:

- Continued diligence in achieving safety and reliability;
- Improving economic competitiveness;
- Achieving and retaining public confidence in nuclear power;
- Retaining and developing the necessary workforce competences;
- Continuing successful management of spent fuel and radioactive waste;
- Demonstrating the successful ultimate disposal of spent fuel and high-level waste;
- Management and acceptance of the transport of nuclear fuel;
- Maintaining confidence in nuclear non-proliferation and nuclear security;
- Establishing acceptable infrastructure in countries introducing nuclear power;
- Achieving proven reactor designs appropriate to specific countries;
- Achieving, for the long term, effective and sustainable use of resources.

New Plant Costs[55]

There has been little hard evidence of recent U.S. nuclear developments from which reasonable cost estimates can be made. However, the table below contains current information from the Northwest Power and Conservation Council and International Atomic Energy Agency that can shed some light on international nuclear developments. Please

[54] International Status and Prospects of Nuclear Power, IAEA, 2008
[55] The information provided in this section has been adapted from a Northwest Power and Conservation Council presentation titled "Costs and Prospects for New Nuclear Reactors", which was developed and presented by Jim Harding in February 2007.

note that these figures reflect "overnight" costs as opposed to "all-in" costs, meaning that they assume the plant could be acquired overnight and thus, no interest or related development cost risks are assessed for the seven to ten year development period.

Figure F-30
Nuclear Plant Capital Costs

Plant Name	Location	COD	"Overnight" Cost (in 2002 dollars)
Genkai 3	Japan	1994	$2818/kW
Genkai 4	Japan	1997	$2218/kW
Onagawa	Japan	2002	$2409/kW
KK6	Japan	1996	$2020/kW
KK7	Japan	1997	$1790/kW
Yonggwang 5&6	Korea	2004/5	$1800/kW
Olkiluoto 3	Finland	2010-2011	$2500-3000/kW

Plant Name	Location	COD	"Overnight" Cost (in 2007 dollars)
Turkey Point	USA-Florida	Proposed	$3,108 - $4,540/kW
Levy	USA-Florida	Proposed	$4,260/kW
Connecticut IRP	USA-Connecticut	Study Estimate	$4,038/kW

Source: Northwest Power and Conservation Council

As Figure F-30 illustrates, the average "overnight" cost of the seven recently-built units is $2,130 per kW in 2002 dollars, and two proposed units in 2007 dollars. These figures do not reflect the impact of escalation to 2009 dollars. Further, they do not reflect the impact of nuclear fuel cost increases, which have risen significantly since 2002.

Florida Power & Light filed a Petition for Determination of Need with the Florida Public Service Commission (PSC) in October 2007 for two new nuclear units at its Turkey Point site. FP&L provided a nonbinding estimate for overnight capital costs of between $3,108 per kWe and $4,540 per kWe (2007 dollars), depending on the cost of materials escalation, owner's scope and cost, and transmission integration required. FP&L based its estimate on an earlier study done by the Tennessee Valley Authority (TVA) for its Bellefonte site, adjusted for site-specific factors and elements not included in the TVA study.

Progress Energy Florida filed a Petition for Determination of Need with the Florida PSC in March 2008 for its proposed Levy nuclear power plant. Progress' non-binding overnight cost estimate for its two-unit greenfield site is $4,260 per kWe (2007 dollars). This initial estimate does not include the cost of transmission system upgrades, which will be necessary to accommodate the new units.

Connecticut Integrated Resource Plan (IRP). In January 2008, the Brattle Group, under contract to Connecticut Light and Power and United Illuminating, published an IRP for the state of Connecticut. The IRP assumed an overnight capital cost for new nuclear of $4,038 per kWe (2008 dollars) and an operating cost of $83.40 per MWh.

In October 2007, Moody's delivered a rather negative analysis of the U.S. nuclear sector [56], saying it did "…not believe the sector will bring more than one or two new nuclear plants online by 2015." Moody's further stated that it believed many of the current expectations for nuclear were "overly ambitious." Moody's June Global Credit Research paper concluded, "The cost and complexity of building a new nuclear power plant could weaken the credit metrics of an electric utility and potentially pressure its credit ratings several years into the project." Moreover, the Nuclear Energy Institute, the industry's trade organization, has stated, "There is considerable uncertainty about the capital cost of new nuclear generating capacity."

[56] Moody's Corporate Finance, "New Nuclear Generation in the United States: Keeping Options Open vs. Addressing An Inevitable Necessity", Special Comment, October 2007